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Closed-Cycle Cooling Systems for Steam-Electric Power Plants A State-of-the-Art Manual

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ABSTRACT

A technical review of the state-of-the-art of thermal pollution control and treatment of cooling water in the steam-electric power generation industry has been performed and is presented in a practical manual format.

The manual provides an assessment of current, near horizon, and future technologies utilized or anticipated to be used with closed-cycle cooling systems. The manual is organized into several basic parts for ease of reference, including the design and operation of closed-cycle cooling systems, their capital and operating costs, methods of evaluation and comparison, water treatment, environmental assessment of water and nonwater impacts, permits required to build and operate, and a brief discussion of benefit-cost analyses.

The manual provides sufficient information to allow an understanding of the major parameters which are important to the design, licensing, and operation of closed-cycle cooling systems. It was prepared for engineers, technical managers, and federal and state regulatory agency staffs, who must evaluate and render judgments on the application and use of these systems.

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SECTION 1

INTRODUCTION

1.1 PURPOSE

The purpose of this manual is to provide a user-oriented practical handbook on closed-cycle cooling systems for fossil- and nuclear-fueled steam electric generating stations. This document has been written for engineers, technical managers, and state and federal regulatory staffs who must deal with all aspects of power plant cooling systems. The manual is intended to provide a broad understanding on the subject, not to serve as a design or technical specification manual. It includes fundamental, technical, and practical information, which reflects the progress and experiences gained in utilizing closed-cycle cooling systems in the steam-electric industry.

The manual can be characterized as providing an assessment of current, near horizon, and future technologies. Current technologies include those technologies in extensive use in the electric power industry. Near horizon technologies are those which are in wide use in other industrial areas or which may have already had limited use in the steam electric industry. Future technologies are defined as those technologies which have not yet been deployed extensively in any industry or those which have had limited industrial use.

This manual is organized into several basic parts for ease of reference. A description of the design and operation of current, near horizon, and advanced closed-cycle cooling systems, including the capital and operating costs, are presented in Sections 2 through 6. Current, near horizon, and future methods available for water treatment of make-up, circulating, and blowdown waters are presented in Sections 7 though 10. The environmental impacts of the closed-cycle cooling systems, the consumptive water use, the permits required to build and operate these systems, and a discussion of the environmental cost-benefit analysis are presented in Section 11. References are included in each of the sections.

1.2 CLOSED-CYCLE COOLING SYSTEMS

The current state-of-the-art in closed-cycle condenser cooling includes mechanical draft, natural draft, fan-assisted natural draft wet and dry cooling towers, cooling ponds and lakes, and spray ponds. These cooling systems are currently being proposed for most new power plant construction except those plants proposed for ocean or Great Lakes sites.

The manual provides sufficient information on each of these heat rejection systems to allow an understanding of those major parameters which are important to the design and operation of each system. In addition, information is provided on several methods used for the economic evaluation of closed-cycle cooling systems and capital and operating costs for all of the conventional cooling systems using one of the methods of evaluation.

Closed-cycle cooling systems have unique environmental/economic impacts associated with them; e.g., the vapor plume of low profile cooling towers may reduce visibility or cause icing on roads and bridges, while evaporative heat rejection may deplete the available water in rivers and streams during low water periods. In order to minimize these impacts, the cooling tower industry and government agencies have developed and evaluated a number of new systems, which can potentially minimize these effects.

Two of these newly developed systems, wet/dry cooling for plume abatement and wet/dry cooling for water conservation, have been offered by cooling tower manufacturers and have been purchased for use in the late 1970- early 1980 time frame. Since there is no current industrial experience for these two systems, they have been designated as near horizon technology in this manual. Economic costs and design descriptions of these systems as described in several published studies have been included.

Those systems which have not yet been offered by industry but have undergone evaluation and/or development by the Federal Government have been designated as future technology. A description of each system and its development status are included.

1.3 WATER TREATMENT FOR CLOSED-CYCLE COOLING

The current state-of-the-art for closed-cycle water treatment has been limited primarily to acid or base addition for pH control and chlorination for controlling biological fouling. This has been possible because of the low number of cycles of concentration at which the systems were operated and the absence of cooling water blowdown regulations. As the use of closed-cycle cooling systems for the electric utility industry increases and more stringent limitations on blowdown are defined, more extensive water treatment will be commonly applied.

The manual provides a description of the problems that occur with closed-cycle cooling operation which will require water treatment and the water treatment methods currently used in industry to alleviate these problems.

Those water treatment methods which are currently applied in other segments of the industrial community have been designated near horizon technology for the purpose of this manual. Descriptions of examples of the application of these water treatment methods on different types of cooling waters, the costs of these treatment methods, and the resulting water quality have also been provided.

Future technologies are those water treatment technologies which are currently used in applications to provide good water quality in relatively small quantities. Although these technologies can have application in the power industry, in most cases, the large volume of water which must be processed makes these technologies economically not feasible.

1.4 ENVIRONMENTAL IMPACTS OF CLOSED-CYCLE COOLING SYSTEMS

The widespread application of closed-cycle cooling in the expanding electric industry will provide new potentially adverse environmental impacts, while minimizing the thermal impacts on the aquatic systems. The environmental impacts of closed-cycle cooling systems can be divided into three broad categories. These are: hydrological and aquatic impacts, atmospheric and terrestrial impacts, and land use, aesthetics and noise impacts.

Hydrological and aquatic impacts are those effects caused by the make-up water intake structure itself, effects due to the water consumption, and effects created by the cooling tower blowdown. Atmospheric and terrestrial impacts are those effects caused by the discharge of large quantities of warm, humid air into the atmosphere, as well as effects on biota due to the entrained impurities in the discharged vapor. Land use, aesthetics, and noise impacts are those effects related to the quantity and utilization of land required by the various closed-cycle cooling systems, their visual impacts and noise generated by the various systems on the environment as a whole. Each of these impacts is discussed and the available methods of prediction and minimization are provided.

A brief description of the important permits required to initiate construction and operation of closed-cycle cooling systems is provided, as well as an integrated method of display of the costs and benefits of alternative cooling systems.

SECTION 2

HEAT REJECTION AND POWER PRODUCTION FROM STEAM ELECTRIC POWER PLANTS

2.1 BASIC POWER PLANT AND COOLING SYSTEM COMPONENTS

2.1.1 Power Plant Components(1-4)*

The basic components of steam-electric power plants using either fossil or nuclear fuel are shown in Figures 2.1a, b, and c. The components to the right of Section A-A in Figure 2.1a are common to all steam-electric power plants. The components to the left of A-A belong to the steam generation system which provides the major distinction between the fossil- and nuclear-fueled plants.

The operation of the steam cycle of a steam-electric power plant is basically as follows: steam at high temperature and pressure enters a turbine where energy in the form of shaft work is removed; the turbine shaft is coupled to a generator which produces electricity; the exhaust steam from the turbine enters a condenser where it is converted to a liquid phase (condensate) by continual removal of latent heat in the exhaust steam; the waste heat; the condensate then returns to the steam generator to complete the cycle.

2.1.1.1 Light Water Reactor (LWR) Power Plant--

A light water reactor plant may be either a pressurized water reactor (PWR) or a boiling water reactor (BWR) power plant. The components shown to the left of Section A-A in Figure 2.1a represent a power plant with a pressurized water reactor. Heat from the reactor is transferred to a steam generator by means of water in a closed circuit system under a pressure of about 2300 psig. Steam leaves the steam generator at a pressure of about 1000 psig. Figure 2.1b shows the components to the left of Section A-A (Figure 2.1a) in a boiling water reactor. In a BWR plant, steam is generated directly in the reactor vessel. Both water and steam are at a pressure of about 1000 psig. In either the PWR or BWR reactor vessel, the maximum steam or circulating water temperature is about 600°F. This temperature is governed by the heat transfer characteristics at the surface of the

---

*Indicates references at the end of each section.

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uranium dioxide fuel rods to limit the maximum temperature of the fuel. This temperature limitation is responsible for the relatively low thermal efficiencies of the present day nuclear power plants.

2.1.1.2 Fossil Power Plants--

Figure 2.1c shows the components to the left of Section A-A in Figure 2.1a for a fossil-fueled steam-electric power plant. In terms of components, it is similar to those of a BWR plant, except that steam is produced in a boiler by the burning of coal, gas or oil. Current large fossil plants are designed with a steam pressure of 2400 psig to 3500 psig and superheat and reheat steam temperatures of approximately 1000°F and 1000°F, respectively.

2.1.2 Cooling System Components(5-7)

The cooling system which rejects the power plant waste heat is shown to the right of Section B-B in Figure 2.1a. A cooling system is termed "once-through" (open-cycle) when the cooling water flow is circulated only once through the system, and waste heat is discharged into natural bodies of water, such as rivers, lakes or coastal waters. A cooling system is termed "closed-cycle" when the cooling water is recirculated, and waste heat is rejected to the atmosphere by such "terminal heat sink devices" as evaporative cooling towers, cooling ponds, spray ponds, and dry cooling towers. In certain cases a cooling pond or wet cooling tower is combined with a once-through system to discharge to the atmosphere a portion of the total waste heat through the device before the rest is discharged to a natural body of water. This type of open-cycle cooling system is sometimes called a "topping" or "helper" system.

This manual discusses the closed-cycle cooling systems for both fossil and light water reactor power plants. The major components of a closed-cycle cooling system (shown to the right of Section B-B in Figure 2.1a) include the condenser, the circulating water pump, piping and associated equipment, and the terminal heat sink device, e.g., cooling tower or cooling pond. A cooling system may also include: 1) a make-up water system which supplies make-up water to replace the loss of circulating water through evaporation, drift, blowdown, and leakage, 2) a blowdown treatment and disposal system, and 3) a water treatment system which treats the make-up and circulating water to prevent or minimize scaling, corrosion, and fouling.

2.2 POWER PLANT CYCLE AND THERMAL EFFICIENCY(1,2)

The Rankine cycle of the steam-electric power plant shown in Figure 2.1 is illustrated in the temperature-entropy diagram of Figure 2.2. Liquid water is compressed isentropically from a to b in the feedwater pump. From b to c, heat is added reversibly in the compressed liquid, two-phase, and superheated states of water in the steam generator and superheater. Isentropic expansion of steam through the turbine with shaft work output takes place from c to d. Condensation of the spent steam takes place from d to a with the rejection of waste heat to the atmospheric heat sink.

The thermal efficiency of the cycle is defined as the ratio of the net work output to heat input of the cycle. The theoretical maximum efficiency of all ideal heat cycles operating between given temperature limits, including the (ideal) Rankine cycle, is the Carnot efficiency. The Carnot efficiency is determined by the temperature of the heat sources and the temperature of the surroundings which serve as a heat sink and is given by:

$$\eta_{max} = \left[1 - \frac{T_{sink}}{T_{source}}\right] \times 100\% \qquad (2.1)$$

where the temperatures are measured on an absolute scale.

Equation (2.1) indicates that there are three choices for improving the ideal cycle efficiency; that is, decreasing T_{sink}, increasing T_{source} or varying both to reduce the ratio, T_{sink}/T_{source}. Modern steam electric power plants utilize improved variations of the basic Rankine cycle which effectively increase the heat source temperature and the cycle efficiency. In this section, a brief description will be given for the modern fossil and nuclear steam cycles and the associated thermal efficiencies. The effect of heat sink temperature as determined by the cooling system performance will be discussed in Section 2.3.

2.2.1 Steam Cycle for Fossil and Light Water Reactor Power Plants

One improvement to the Rankine cycle is the adoption of regenerative feedwater heating. It is done by extracting steam at various stages in the turbine to heat the feedwater as it is pumped from the condenser hotwell to the boiler. Regenerative heating not only improves cycle efficiency, but has other advantages; among them are lower volume of steam flow in the final turbine stages and a convenient means of deaerating the feedwater.

Where maximum temperatures are limited by physical or economic means, reheating of steam after its partial expansion in the turbine can be used as an effective means of raising the average temperature of the heat source and, thus, the thermal efficiency of the cycle. Reheat also reduces the moisture of the steam in the low pressure turbine stages. Reduction of moisture improves the expansion efficiency and provides an effective means to control blade and nozzle erosion.

Figure 2.3 shows the cycle diagram of a typical fossil power plant, illustrating schematically the arrangement of various components, including the steam reheater and feedwater heaters. As shown in Figure 2.3, steam is reheated after expansion through the high pressure turbine. The temperature-entropy diagram for the cycle shown in Figure 2.3 is given in Figure 2.4 for a supercritical throttle steam condition of 3515 psia and 1000F and a reheat steam condition of 540 psia and 1000F. This figure illustrates how the principle of regenerative feedwater heating and steam reheat increases the mean temperature level for heat addition. Consequently, the maximum cycle thermal efficiency is increased (See Equation (2.1))

Figure 2.5 illustrates a Rankine cycle whose thermal energy source is a light water reactor system. Pressure and temperature limitations required for a nuclear reactor mean that the steam leaving the steam generator is either saturated or slightly supersaturated and that expansion through the power cycle is largely in the region of wet steam. Three different methods are generally utilized for moisture removal, which both improve the thermal efficiency and minimize blade erosion. After expansion in the high pressure turbine, the steam passes through an external moisture separator. After passing through the external moisture separator, the steam is then reheated, increasing its temperature and reducing its moisture content. Current plant designs also include mechanical moisture separation in the low pressure turbine blades. These separations utilize grooves on the back of the turbine blades to drain the collected moisture.

2.2.2 Thermal Efficiency and Waste Heat Rejection

2.2.2.1 Thermal Efficiency--

As indicated earlier, the performance of a steam cycle plant can be expressed in terms of cycle thermal efficiency, η, or cycle heat rate, HR. The thermal efficiency is expressed as a dimensionless parameter, while the heat rate is expressed as a dimensioned parameter.

1) Cycle thermal efficiency, η :

$$\eta = \frac{\text{Net power output from the steam cycle}}{\text{Heat input to the steam cycle}} \qquad (2.2)$$

2) Cycle heat rate, HR:

$$HR = \frac{\text{Heat input to cycle in Btu/hr}}{\text{Net power output from cycle in kW}}, \text{ Btu/Kwh} \qquad (2.3)$$

The cycle thermal efficiency, expressed as a fraction, and the heat rate are related by the following equation:

$$\eta = \frac{3413}{HR} \tag{2.4}$$

where the numerator is the conversion factor from Btu/hr to kW.

In engineering practice, several other thermal efficiency terms and corresponding heat rate terms have been used in power plant applications. These are: 1) gross plant efficiency and gross plant heat rate, 2) net plant efficiency and net plant heat rate, and 3) net station efficiency and net station heat rate. The definitions of these efficiency terms are as follows:

1) Gross plant efficiency, η_g :

$$\eta_g = \frac{\text{Turbine-generator output}}{\text{Heat input to the steam cycle}} \tag{2.5}$$

The turbine-generator output is the electric output at the generator, and it is equal to the turbine output less the loss in the generator.

2) Net plant efficiency, η_p :

$$\eta_p = \frac{\text{Electric output at bus bar}}{\text{Heat input to the steam cycle}} \tag{2.6}$$

The electric output at bus bar is equal to turbine-generator output less the sum of the plant auxiliary power requirements, e.g., pumps and fans, air conditioners, lights, etc.

3) Net station efficiency, η_{st} :

$$\eta_{st} = \frac{\text{Electric output at bus bar}}{\text{Heat input to station}} \tag{2.7}$$

For nuclear power plants, the heat input to the station is theoretically equal to the heat input to the cycle, neglecting the heat losses in the primary reactor coolant circuit. For fossil plants, the heat input to the station is equal to the sum of the heat loss through the smoke stack and the heat input to the steam cycle. Therefore, for nuclear plants, the net plant efficiency and the net station efficiency are equal; for fossil plants, the net station efficiency is equal to the net plant efficiency times a boiler efficiency, η_b , defined as:

$$\eta_b = \frac{\text{Heat input to the steam cycle}}{\text{Heat input to the boiler}} \qquad (2.8)$$

2.2.2.2 Waste Heat Rejection Rate--

The heat rejection rate of a power plant to its condenser cooling system can be calculated by the following equation, given the cycle heat rate and net cycle power output:

$$Q_{rej} = (HR - 3413) \times P \times 1000 \qquad (2.9)$$

where:

Q_{rej} = heat rejection rate to the condenser cooling system, Btu/hr.

HR = cycle heat rate, Btu/kWh.

P = net cycle power output, MW.

The above equation is derived from the energy equation for the steam cycle and the definitions of cycle thermal efficiency, heat rate, and power.

It has been common practice, however, to use the turbine-generator output and the corresponding heat rate to calculate the heat rejection for sizing a cooling system. This practice gives a more conservative estimate of the heat rejection rate.

2.3 EFFECT OF COOLING SYSTEM PERFORMANCE ON POWER PLANT PERFORMANCE

The cooling system used with a steam electric power plant determines the lowest or the heat sink temperature in the thermodynamic cycle of the power plant. Ideally, this temperature is the steam condensing temperature. Since the cycle thermal efficiency increases as the heat sink temperature decreases (assuming all other conditions remain constant), it is desirable to reject the waste heat at the lowest possible temperature. Thus, a lower exhaust pressure means higher efficiency and more useful work by the turbine.

The effect of the steam condensing temperature on the turbine exhaust pressure and the plant efficiency is generally presented in terms of steam turbine heat rate corrections versus turbine exhaust pressure curves or heat rate tables(8). These heat rate corrections and the corresponding outputs are different for different power plant cycles and specific power plants, as well as different load conditions. The corrections represent the change in heat rate relative to a fixed reference heat rate, called base heat rate, at a particular exhaust pressure. Typical heat rate corrections for 1000-MWe fossil and light water reactor power plants operated with conventional turbines at valve wide-open conditions are shown in Figures 2.6 and 2.7, respectively.

It should be noted that for a fixed heat input to the power cycle, the product of power output and its corresponding heat rate at any exhaust pressure within the operational range is always equal to the product of the base output and the base heat rate. This relationship allows the determination of plant output at off-design conditions.

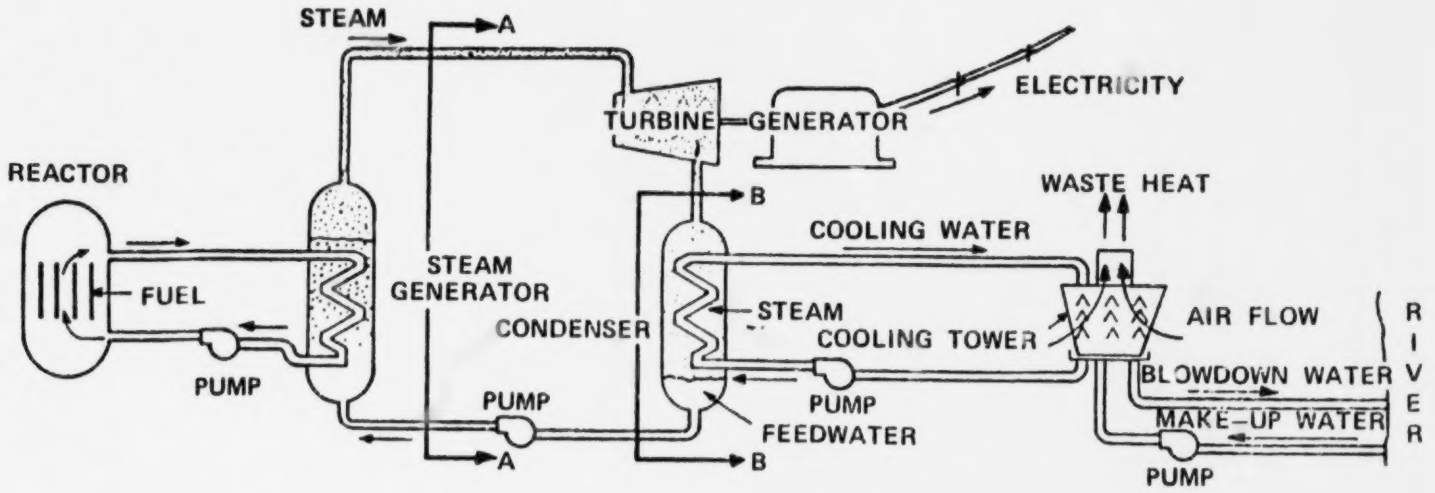
STEAM
A
A
REACTOR
FUEL
PUMP
STEAM GENERATOR
PUMP
TURBINE
GENERATOR
ELECTRICITY
B
B
CONDENSER
STEAM
PUMP
FEEDWATER
COOLING WATER
WASTE HEAT
COOLING TOWER
AIR FLOW
BLOWDOWN WATER
MAKE-UP WATER
PUMP
RIVER

Figure 2.1a. Power generation and waste heat rejection - Pressurized Water Reactor (PWR) with evaporative cooling tower.

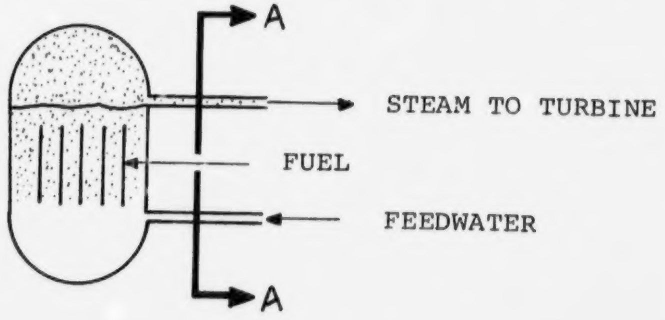
A
STEAM TO TURBINE
FUEL
FEEDWATER
A

Figure 2.1b. Boiling water reactor.

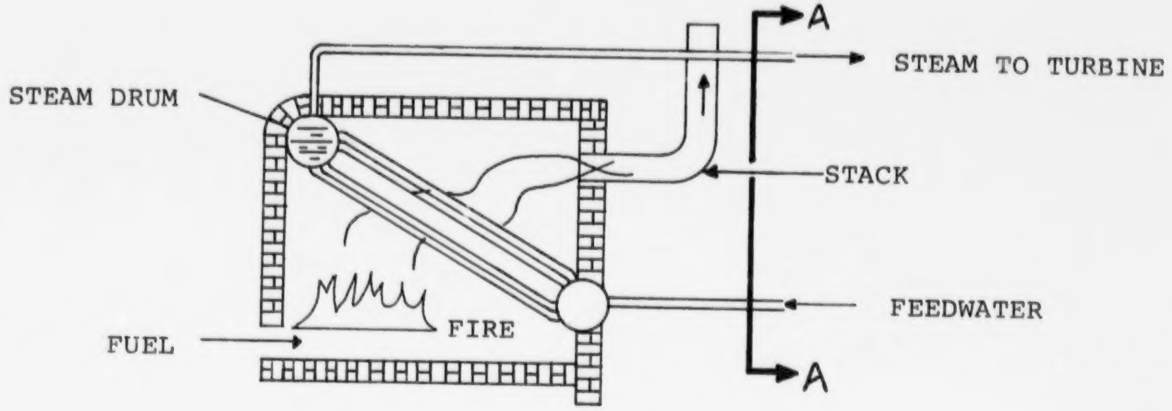
A
STEAM TO TURBINE
STEAM DRUM
STACK
FEEDWATER
FIRE
FUEL
A

Figure 2.1c. Fossil fuel-fired boiler.

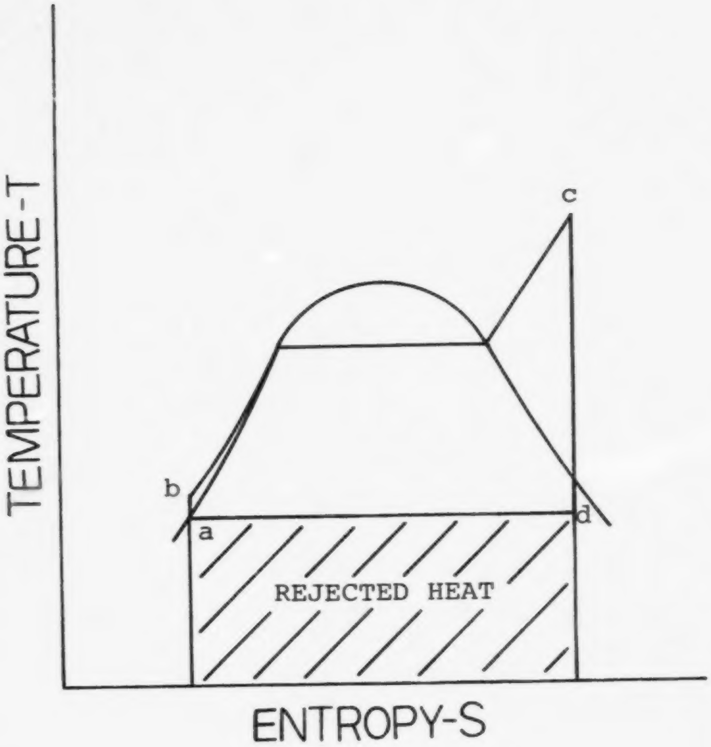
TEMPERATURE-T
c
b
a
d
REJECTED HEAT
ENTROPY-S

Figure 2.2. Temperature-entropy diagram of the ideal Rankine cycle.

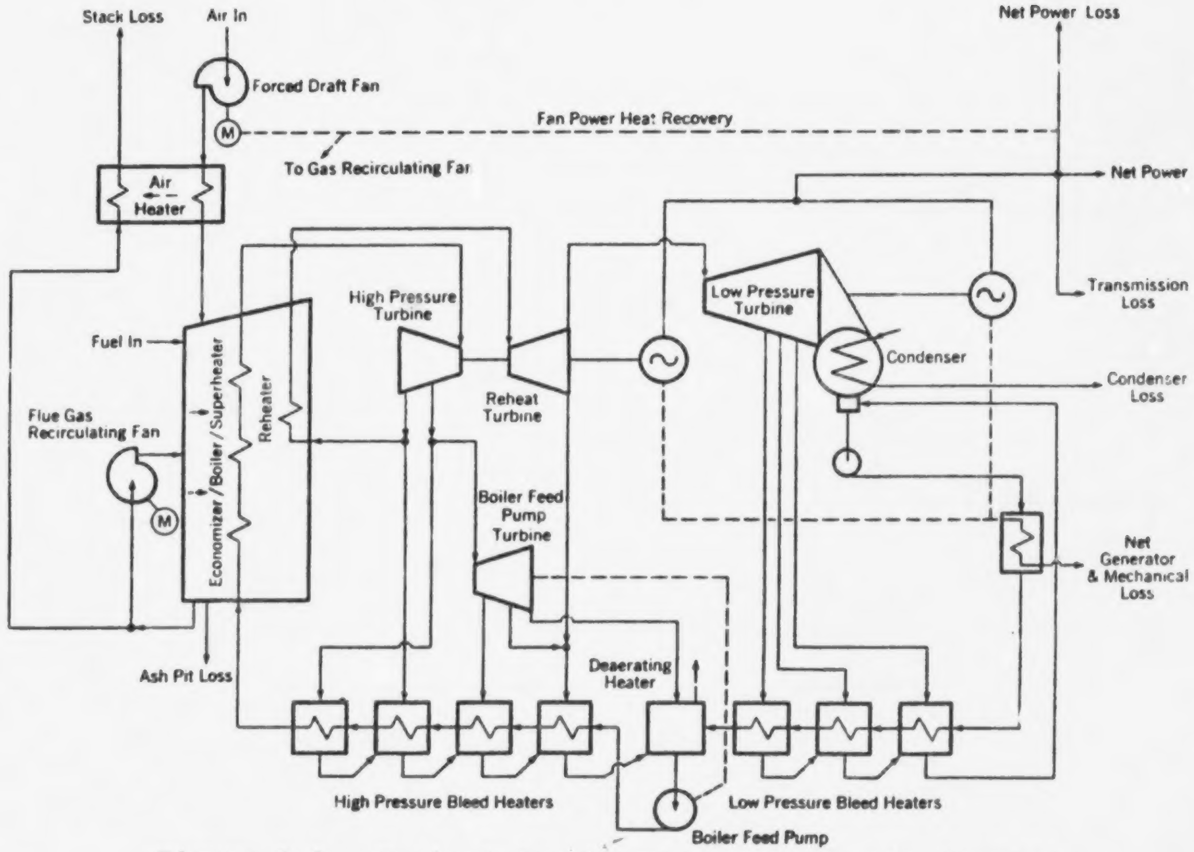
Stack Loss
Air In
Forced Draft Fan
M
Fan Power Heat Recovery
To Gas Recirculating Far
Air Heater
Net Power Loss
Net Power
Transmission Loss
Fuel In
Economizer / Boiler / Superheater
Reheater
Flue Gas Recirculating Fan
M
High Pressure Turbine
Reheat Turbine
Low Pressure Turbine
Condenser
Condenser Loss
Boiler Feed Pump Turbine
Net Generator & Mechanical Loss
Ash Pit Loss
Deaerating Heater
High Pressure Bleed Heaters
Low Pressure Bleed Heaters
Boiler Feed Pump

Figure 2.3. Typical fossil power plant cycle diagram (single reheat, 8-stage regenerative feedwater heating)(1). Reprinted from Steam--Its Generation and Use, 1972, with permission of Babcock & Wilcox Company.

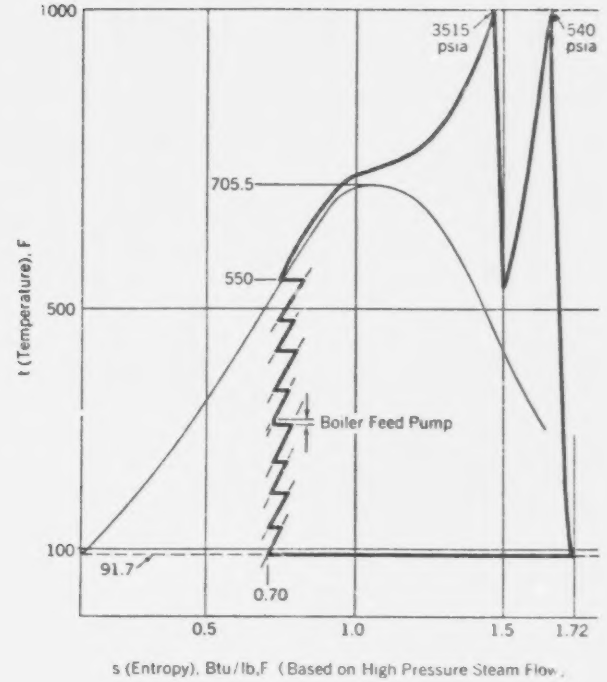

Figure 2.4. Steam cycle for fossil fuel--temperature-entropy diagram--single reheat, 8-stage regenerative feed heating--3515 psia, 1000F/1000F steam(1). Reprinted from Steam--Its Generation and Use, 1972 with permission of Babcock & Wilcox Company.

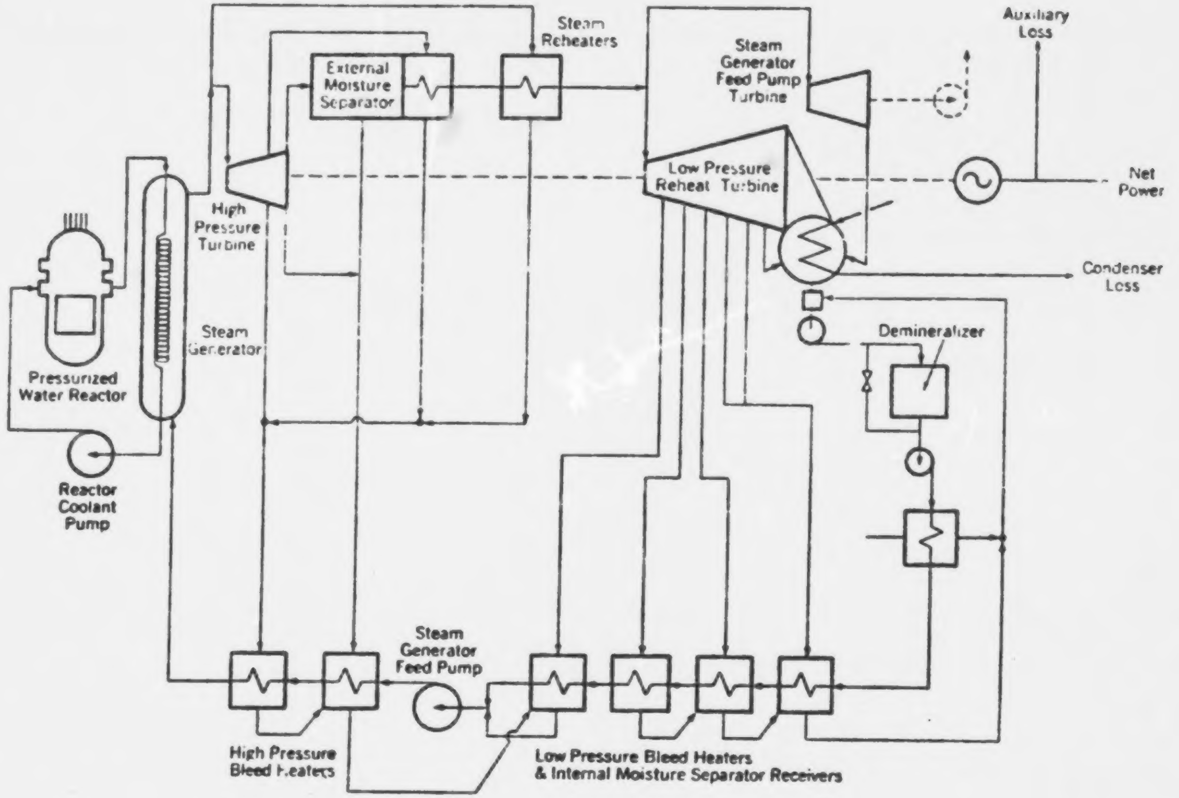
Steam Reheaters
External Moisture Separator
Steam Generator Feed Pump Turbine
Auxiliary Loss
Low Pressure Reheat Turbine
Net Power
High Pressure Turbine
Condenser Loss
Steam Generator
Demineralizer
Pressurized Water Reactor
Reactor Coolant Pump
Steam Generator Feed Pump
High Pressure Bleed Heaters
Low Pressure Bleed Heaters & Internal Moisture Separator Receivers

Figure 2.5. Typical nuclear power plant cycle diagram(1). Reprinted from Steam--Its Generation and Use, 1972, with permission of Babcock & Wilcox Company.

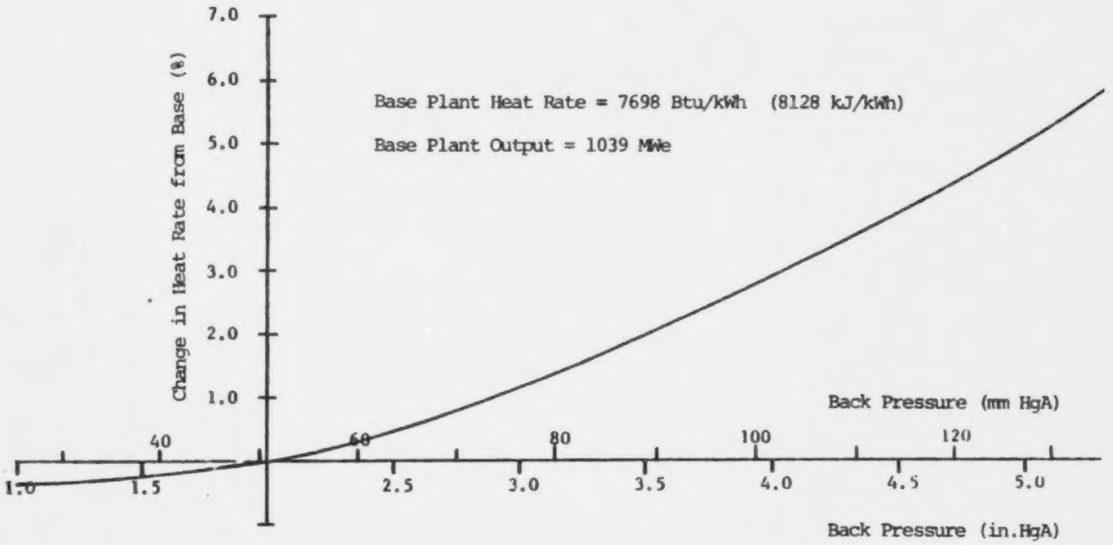

Figure 2.6. Typical heat rate correction curve for a fossil plant with a conventional turbine(6,7).

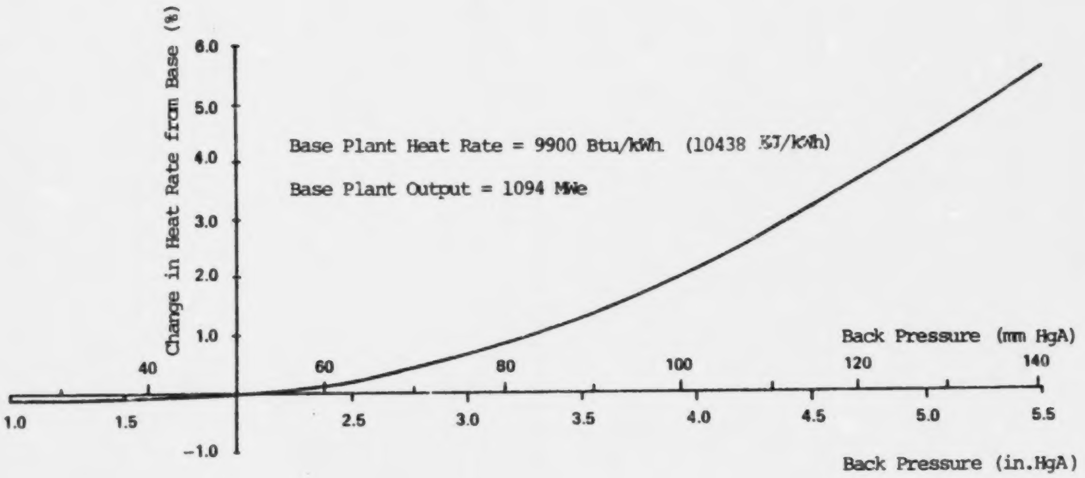

Figure 2.7. Typical heat rate correction curve for a nuclear plant with a conventional turbine(5,7).

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SECTION 3

ECONOMIC EVALUATION OF ALTERNATE COOLING SYSTEMS

3.1 METHODS OF ECONOMIC EVALUATION

3.1.1 General Description

In order to assess alternate cooling systems on a common economic basis, several penalty costs must be included in the evaluation in addition to the capital cost of the equipment and its installation. Common to all cooling system evaluations are the penalties incurred to account for: 1) the loss of plant performance (capacity and energy) at elevated temperatures, 2) the power and energy required to operate the cooling system, and 3) the cooling system maintenance requirements. Other penalties may be included under special circumstances. For instance, the cost incurred for the purchase of water and the capital and operating costs of the water supply, treatment, and blowdown disposal systems may be included.

The evaluation of capacity and energy penalties depends both on how the loss of plant performance is assessed and how that loss is made up. For these reasons, three different methods have been used in the economic evaluations of cooling system alternatives(1-6). These methods have been categorized by Fryer(7) as follows:

1. Fixed demand/fixed heat source method
2. Fixed demand/scalable steam source-scalable plant method
3. Negotiable demand/fixed heat source method.

In the first two methods, a fixed demand or load is imposed on the plant. This fixed demand serves as the basis from which the loss of plant performance can be assessed. In other words, as the plant output changes due to changes in cooling system performance, the capacity and energy generated are compared to the fixed demand required of the plant. If the heat source is fixed, the next step is to decide how to meet that demand from generating units other than the plant. The methods of meeting that demand then completely define the capacity and energy penalty assessment. If the scalable steam source method is selected, the next step is to define what fraction of the loss of capacity will be made up by scaling up the size of the heat source, i.e., the entire plant exclusive of the cooling system.

In the third method, the demand is negotiable, meaning that the utility system will take whatever output that the plant is capable of generating. The performance differences of the cooling systems are reflected in the differences in the net energy output. There is no lost capacity or energy to be considered.

3.1.2 Fixed Demand/Fixed Heat Source Method

In the fixed demand/fixed heat source method, it is assumed that a fixed demand is imposed on the plant output. This fixed demand is generally the name plate power output of a reference plant operating with a conventional turbine at a specified turbine back pressure. The power plant under consideration also has identical energy input and plant design as the reference power plant. As the plant performance changes, due to changes in cooling system performance, the capacity and energy generated are compared to the fixed demand required of the plant. If the cooling system caused the plant to operate below the fixed demand, a penalty equivalent to an increase in capital cost is added to the capital cost of the cooling system; credit is taken if the plant operates above the demand value. A penalty is also assessed for the capacity and energy requirements for operating the pumps and fans.

3.1.3 Fixed Demand/Scalable Heat Source Method

The fixed demand/scalable heat source method assumes that while the demand is basically set by the reference plant, the heat source and the balance of the plant can be scaled up in size to provide a part or all of the loss of plant performance. When scaling up the heat source, other plant components must also be increased to accommodate an increased steam flow. For fossil plants the additional scaling up of plant components would include the boiler, superheater, reheater, feedwater heaters, steam pipes, coal handling equipment, turbine-generator, etc. For a nuclear plant, it would include the reactor core and its associated equipment.

Figure 3.1 illustrates the relative performance of a dry cooling plant employing a high back pressure turbine which has undergone both steam source scaling and plant scaling. The steam source has been scaled so that the plant has adequate steam for the same capacity as the reference plant at their respective rated back pressures. In addition, the entire plant has been subsequently scaled up to provide adequate capacity to power the dry cooling system fans and pumps. This is basically the approach used in Reference 5. The amount of scaling can be such that during the coldest temperatures some excess capacity above the fixed demand imposed on the reference plant would exist. However, during the hottest temperature periods a shortage would result, which would have to be made up by some capacity leveling means, such as gas turbines (Figure 3.1).

In some studies which concerned dry cooling systems, the entire plant, including necessary additional steam supply, has been scaled up so that the dry cooling plant will meet the demand or load imposed on the plant even during the highest maximum ambient temperature as shown in Figure 3.2. This represents the maximum amount of scaling that would be required. Excess capacity would exist at all temperatures except at the maximum temperature. On a normalized basis, the same unit costing results from using a derating method.

Steam source and plant size scaling of fossil plants are possible, barring problems of scaling between discrete standard sizes of certain equipment. Scaling of the steam source of a nuclear plant may not be at all possible if the reference plant is at the current U. S. Nuclear Regulatory Commission limits on the thermal power. An alternative method which circumvents this problem is to reduce the load or demand imposed upon the plant, or to essentially derate the dry cooling plant relative to the reference plant as in the method discussed below.

3.1.4 Negotiable Demand/Fixed Heat Source Method

The negotiable demand/fixed heat source method involves a derating process rather than a size scaling process. Barring economics of scale, derating or scaling done to the same proportion should result in the same unit costs. The derating of the load imposed on the dry cooling plant has involved derating the dry cooling plant to the output that it can produce at maximum steam flow during the maximum ambient temperature. Figure 3.3 exemplifies this method. Derating to this level would be a rational approach if the dry cooling plant were isolated and had to meet a constant base load. However, in an actual utility system, it does result in significant and uneconomic excess capacity during the cold periods. On the other hand, no direct energy or capacity must be made up, thereby, greatly simplifying the analysis.

3.2 TREATMENT OF LOSS OF PLANT PERFORMANCE

In this and in subsequent subsections the fixed demand/fixed heat source method of analysis is described in detail. Cooling system costs reported in Sections 4 and 5 are based on this method.

The quantitative evaluation of the loss of plant performance required for assessing the capacity and energy penalties in a fixed demand/fixed heat source evaluation is illustrated in Figure 3.4.

Figure 3.4 shows the typical gross plant output of the reference power plant as a function of ambient temperature and time when the plant is operated. The ambient temperature affects the plant output, since the performance of a cooling system determines the lowest temperature of the thermodynamic cycle and, consequently, the plant output as discussed in Section 2.3. This figure also shows the net plant output obtained by deducting from the gross plant output the capacity required to run the cooling system auxiliary equipment.

The maximum plant capacity deficit with respect to the fixed demand occurs at the highest ambient temperature and represents the capacity replacement needed. This includes both the maximum loss of plant performance, $(\Delta kW)_{max}$, and the coincidental auxiliary power requirement, $(HP)_{aux}$. The hatched area represents the replacement energy required during the annual cycle. The area above the gross plant output curve represents the energy deficit caused by the changes in cooling system performance, whereas the hatched area between the gross plant output and the net plant output curves represents the energy requirement by the cooling system auxiliary equipment, e.g., pumps and fans.

Figure 3.5 shows the relative performance of a power plant with different size cooling systems. As indicated in this figure, when the cooling system size or design changes, the plant performance curves are shifted; both the capacity and energy deficits with respect to the base values change, resulting in different penalty costs for different cooling systems. However, the plant fuel costs will not be affected by the change in cooling systems, because the size of the heat source is kept unchanged regardless of cooling system changes, and the heat source is assumed to operate at full power during the period of the year when it is operating. There is no change in capital cost for the balance of the power plant, as the boiler and the balance of the plant are also assumed to be fixed. Thus, in the fixed source-fixed demand method of analysis, the cost of installation and operation of the boiler and the balance of the plant is not included in an assessment of the penalty cost incurred by the cooling system deficiency.

3.3 CAPACITY AND ENERGY PENALTY ASSESSMENT

The annual capital needed to provide the extra capacity and energy to compensate for the losses as discussed in the previous section are a part of the total penalty cost. In evaluating the penalties, it is assumed that the plant either operates at full capacity or is off-line and has an average capacity factor of a certain percent, e.g., 75 percent.

The equations for evaluation of these annual penalty costs are given below:

Capacity Penalty (P_1):

$$P_1 = \text{afcr} \cdot K \cdot (\Delta kW)_{max} \tag{3.1}$$

Replacement Energy Penalty (P_2):

$$P_2 = \text{cap} \int_0^{8760} \left[\left\{ OAM + F \cdot HR(T) \right\} \cdot \Delta kW(T) \cdot dt \right] \tag{3.2}$$

Cooling System Auxiliary Power (P_3):

$$P_3 = \text{afcr} \cdot K \cdot (HP)_{aux} \tag{3.3}$$

Cooling System Auxiliary Energy (P_4):

$$P_4 = \text{cap} \int_0^{8760} \left[\left\{ OAM + F \cdot HR(T) \right\} \cdot HP(T) \cdot dt \right] \tag{3.4}$$

where:

$(\Delta kW)_{max}$, $\Delta kW(T)$, $(HP)_{aux}$, and $HP(T)$ are shown in Figure 3.1.

and:

afcr = annual fixed charge rate, %/100.

K = capacity penalty charge rate, \$/kW.

$(\Delta kW)_{max}$ = maximum loss of capacity at T_{max}, kW.

T_{max} = peak ambient temperature, ^{o}F.

cap = average capacity factor of the plant, %/100.

OAM = operation and maintenance cost for the generating unit used, \$/kWh.

F = fuel cost for the generating unit used to make up the loss of energy, \$/Btu.

$HR(T)$ = heat rate as a function of ambient temperature for the generating unit used to make up the loss of energy, Btu/kWh.

T = ambient temperature (T is a function of time), ^{o}F.

$\Delta kW(T)$ = loss of capacity at ambient temperature T, kW.

t = time, hr.

$(HP)_{aux}$ = cooling system auxiliary power requirement at T_{max}, kW.

$HP(T)$ = cooling system auxiliary power requirement at ambient temperature T, kW.

The capacity penalty, P_1, and the auxiliary power penalty, P_3, Equations (3.1) and (3.3), are first cost penalties. They represent the capital expenditure for the generating equipment needed to supply the extra power, either by the addition of peaking units (e.g., gas turbine or pumped storage generating units) or by providing excess capacity from base load units in the utility system. These penalties are annualized by the multiplication of an annual fixed charge rate.

The replacement energy penalty, P_2, and the cooling system auxiliary energy, P_4, Equations (3.2) and (3.4), are annual energy cost penalties. These annual energy costs are evaluated by integrating the energy costs for a series of time periods, which add up to a year. Each time period has a constant ambient dry bulb temperature and a coincident and constant wet bulb temperature.

3.4 ECONOMIC FACTORS FOR CAPACITY AND ENERGY PENALTY ASSESSMENT

Since the size of the plant heat source is fixed, the loss of plant capacity and energy will be provided by an outside source. The source of capacity and energy replacements which serves as the basis for the assessment of the associated economic factors K, F, and OAM may include any of the following:

1. High capital cost, low operating cost base load units
2. Low capital cost, high operating cost peaking units
3. A mixture of generating unit types

4. Purchased power from another utility system.

The selection of the capacity replacement is dependent on economics and on the type of duty of the capacity being replaced. For example, for duties which require relatively constant loads or large amounts of energy, the replacement choice on economic grounds should be a base load capacity. Such is the case for the cooling system auxiliary power and also the capacity loss for dry and wet/dry cooling systems during most of a year, except at temperatures near the highest ambient temperature(1,2). A portion of the maximum capacity loss at the highest ambient temperature for a dry cooled plant should be provided by peaking units, such as gas turbines.

3.5 OTHER PENALTY COSTS

3.5.1 Water Cost Penalty

The cost of supplying the make-up water to a plant and the handling of the blowdown disposal consists of the following components:

1. Capital cost for the make-up water supply system
   a. pumps and associated structures
   b. pipelines
2. Pumping cost which includes both the capacity charge for the power required by the pumps and the energy charge for pumping the water
3. Water purchase cost
4. Capital cost of water treatment facilities and operating cost
5. Capital and operating costs for blowdown disposal.

For specific power plants all these component costs can be separately estimated. In the absence of the specific information, a lumped charge for the purchase and treatment cost of make-up water and circulating water can be used.

3.5.2 Cooling System Maintenance Penalty Cost

The cooling system maintenance penalty is the cost charged to a cooling system for services which include periodic maintenance and replacement parts. Cooling system maintenance cost mainly consists of:

1. Lubrication and general inspection of the motors and gearboxes
2. Partial replacement of motors and gearboxes
3. Cleaning of the cold water basins of the wet towers
4. Cleaning and partial replacement of finned tubes for the heat exchangers, if dry towers are used
5. Condenser tube cleaning and tube replacement.

The maintenance costs of various cooling system components are generally calculated as a percentage of the capital cost of these components in the absence of specific cost information for each of the above components.

3.6 TOTAL EVALUATED COST AND OPTIMUM COOLING SYSTEM

The penalty costs evaluated on an annual basis are capitalized over the plant lifetime and added to the capital cost of the cooling system. The sum of the capital cost and the capitalized penalty cost is called the total evaluated cost and is expressed by the following equation:

$$C_t = C + \frac{1}{afcr} \cdot \sum_{j=1}^{N} P_j \qquad (3.5)$$

where:

C_t = total evaluated cost, \$.

C = capital cost of cooling system, \$.

afcr = annual fixed charge rate, %/100.

P_j = annual economic penalty for the jth component, \$.

j = index for penalty cost component.

N = total number of penalty cost components.

This total evaluated cost represents an effective capital cost of the cooling system.

The nature of the total evaluated cost as a function of the design parameters is such that a minimum total evaluated cost system can be identified as shown in Figure 3.6. This minimum total evaluated cost system is called an optimum cooling system, and this cost represents the best trade-off between the capital and penalty costs.

The figure also shows the general trend of capital cost and penalty costs. Varying the size and design of a cooling system will vary the capital cost and penalty costs associated with the system. For example, a large and, consequently, expensive cooling system will have better performance than a smaller version of the same system. The smaller system, however, will have a higher economic penalty.

3.7 ECONOMIC OPTIMIZATION

Economic optimization is the process of selecting the minimum cost cooling system. It includes sizing and costing of a series of cooling systems, determining their thermal performance, water consumption, auxiliary power and energy needs, and the resulting economic penalties during a typical annual cycle. The total evaluated costs of these systems are then determined, and the system with minimum total evaluated cost is selected as the optimum system.

Additional criteria or restrictions may be imposed on the economic optimization. An example is the selection of an optimum wet/dry system for a specific water consumption requirement which serves as an additional criterion(2,3).

The cooling systems are generally sized on the basis of design temperatures using components of standard designs. The major components of a cooling system include the condenser, circulating water pump and motor, the pump structure, the terminal heat sink device, and the connecting pipelines.

The most difficult part of the cooling system design is that of the terminal heat sink device. This is due to the fact that the performance and cost information of a particular cooling device usually falls in the realm of proprietary information. Heat transfer coefficients, pressure drop correlations, and other operational factors are all necessary to size a cooling system and to determine the performance of the cooling system but are difficult to obtain as functions of variables over which a system designer has control. The recourse is to use the standardized designs offered by manufacturers.

The design parameters include wet bulb temperature, dry bulb temperature, approach to wet bulb or dry bulb temperature, cooling range, wind velocity, and other meteorological variables pertinent to the particular cooling system under considertion.

The design approach, range, and terminal temperature difference together define the saturated steam temperature in the condenser and the turbine back pressure. From the turbine heat rate curve, the turbine-generator output (gross plant output) and the amount of heat rejected are determined. The heat load, combined with the given design temperatures, determines the size of the various cooling system components.

Once a system is designed, the performance of the system can be evaluated at off-design ambient conditions. The performance of one component will influence that of the others. Consequently, the performance of the plant, as a function of the ambient conditions, has to be considered simultaneously with the condenser and the terminal heat sink device.

The cost and design obtained with this approach is sufficently accurate for budgeting purposes and economic comparisons with alternative cooling systems as indicated in Reference 1.

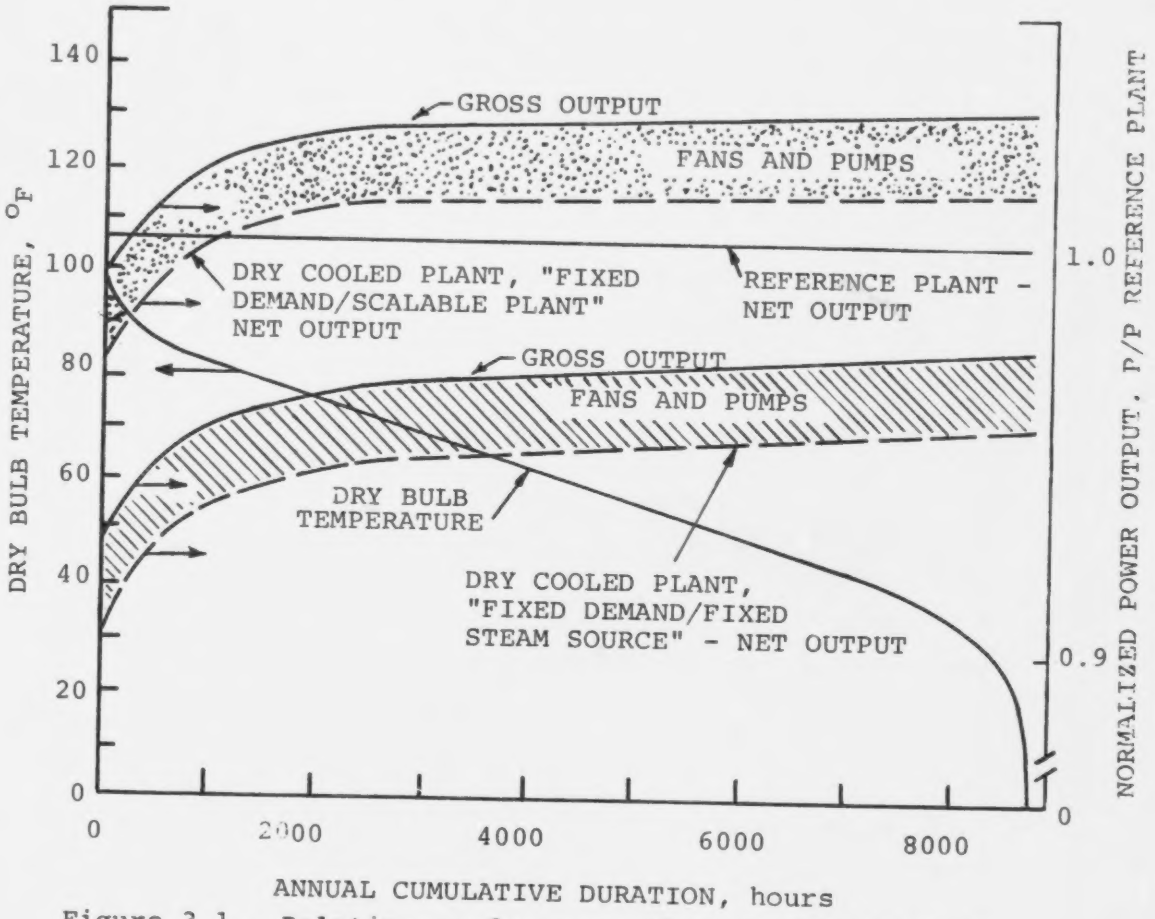

Figure 3.1. Relative performance of a dry cooled plant utilizing a high back pressure turbine under the fixed demand/scalable steam source/scalable plant approach.

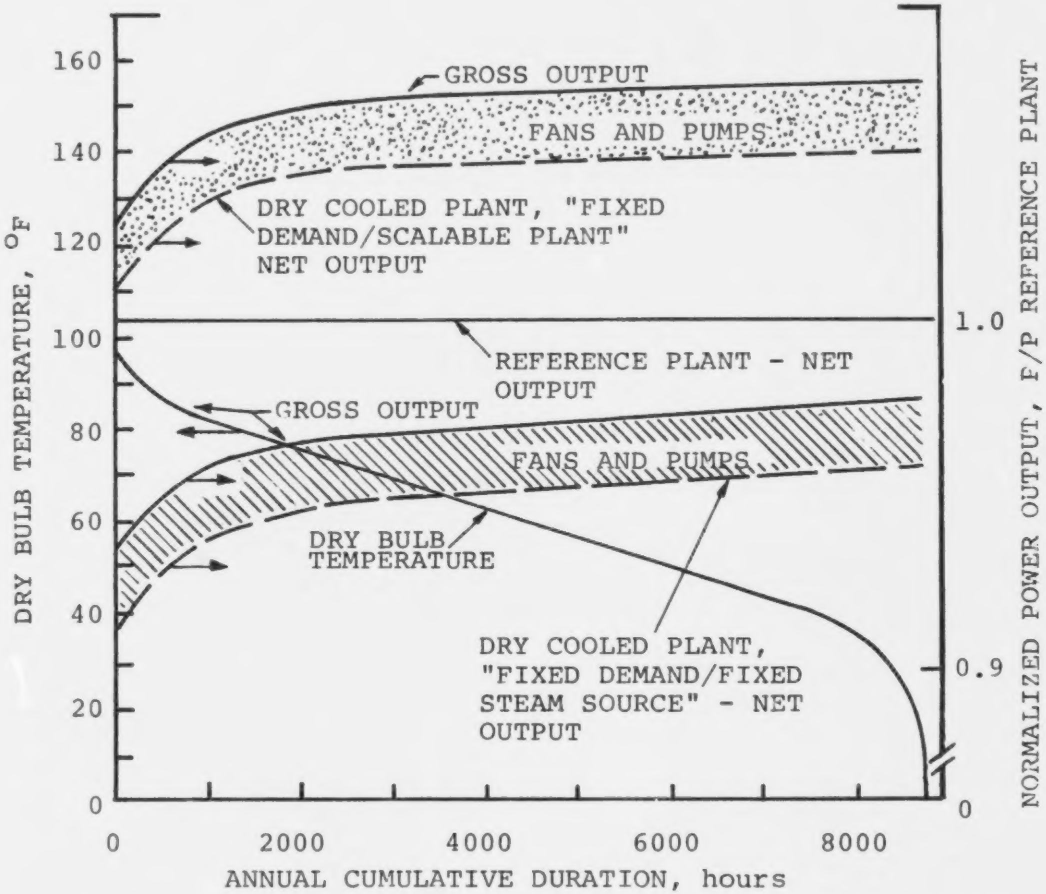

Figure 3.2. Relative performance of a dry cooled plant utilizing a high back pressure turbine under the fixed demand/scalable steam source/scalable plant approach with maximum required scaling.

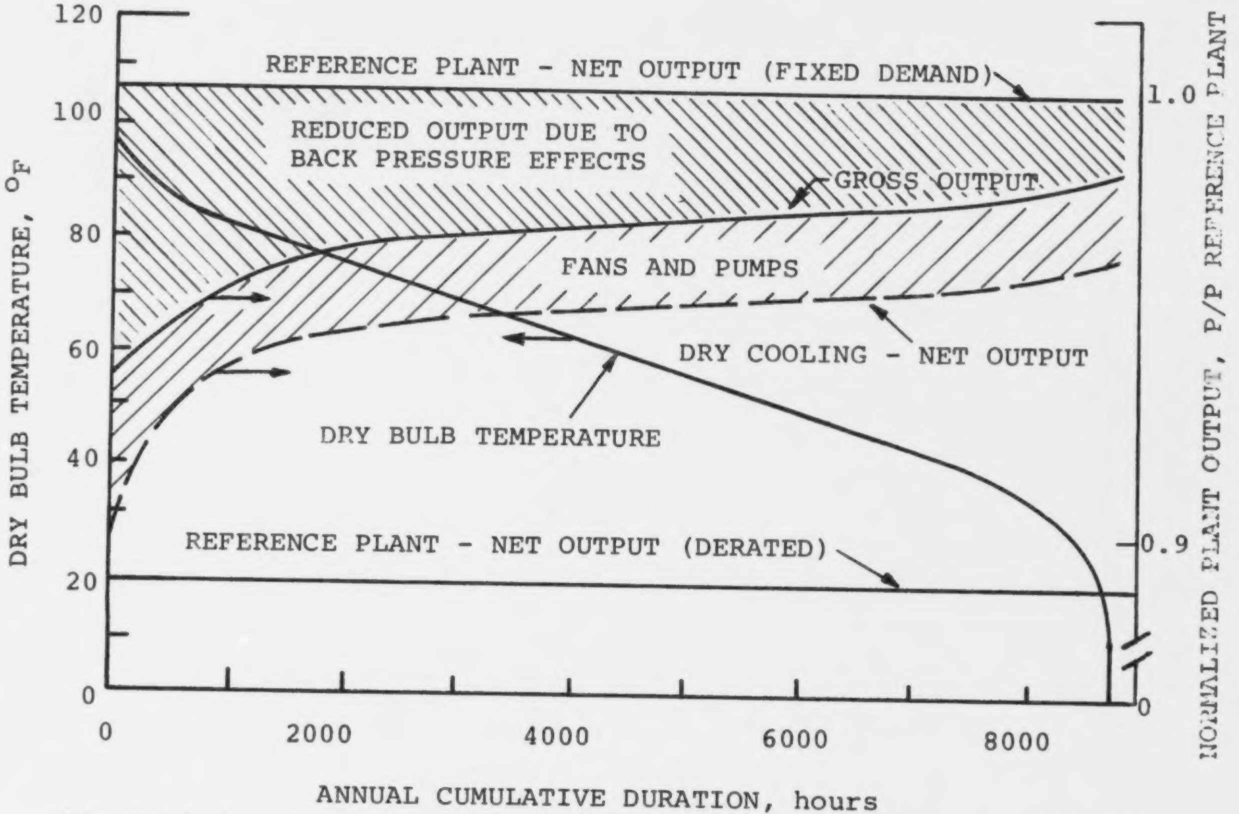

Figure 3.3. Relative performance of a dry cooled plant utilizing a high back pressure turbine under the negotiable demand/fixed heat source approach with maximum required derating.

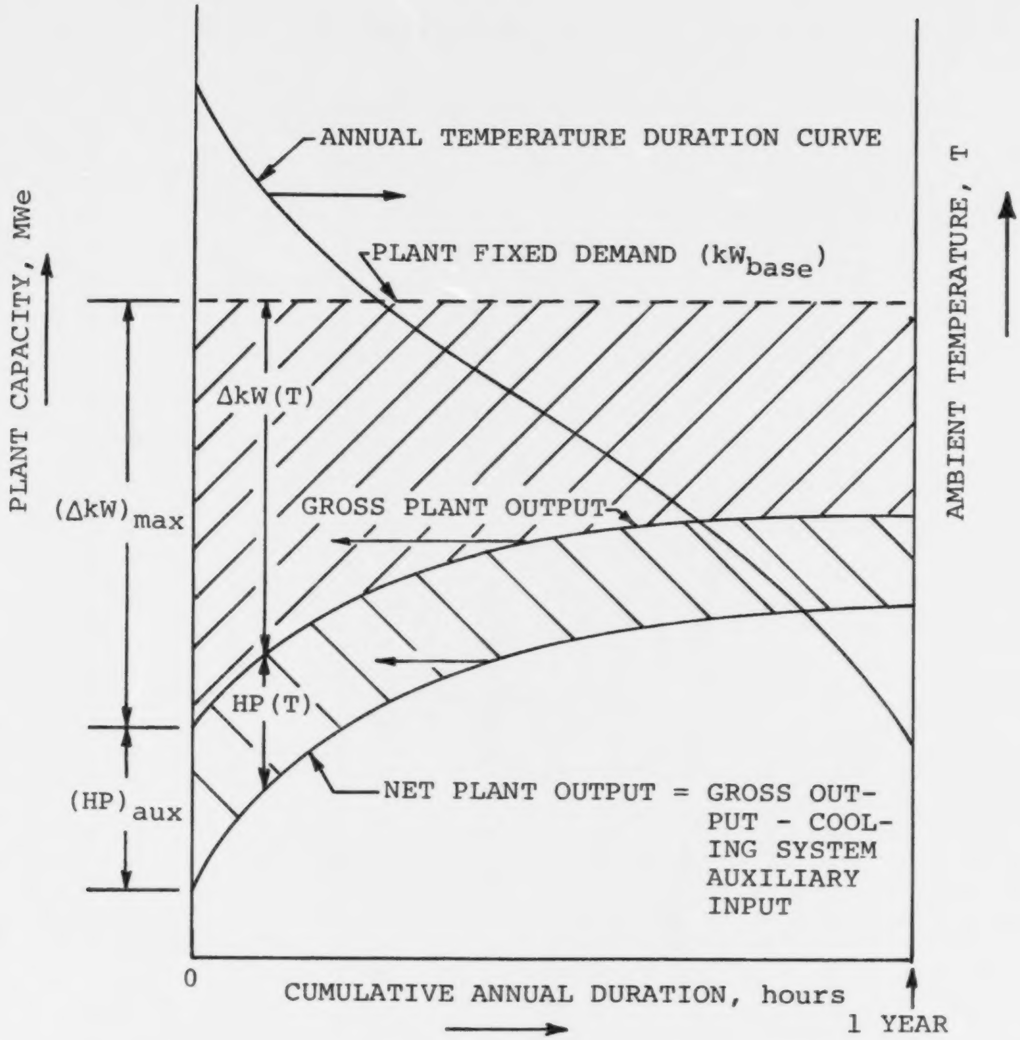
ANNUAL TEMPERATURE DURATION CURVE
PLANT FIXED DEMAND (kW_{base})
PLANT CAPACITY, MWe
AMBIENT TEMPERATURE, T
ΔkW(T)
(ΔkW)max
GROSS PLANT OUTPUT
HP(T)
(HP)aux
NET PLANT OUTPUT = GROSS OUTPUT - COOLING SYSTEM AUXILIARY INPUT
0
CUMULATIVE ANNUAL DURATION, hours
1 YEAR

Figure 3.4. Ambient temperature duration and corresponding plant performance for fixed demand/fixed heat source approach.

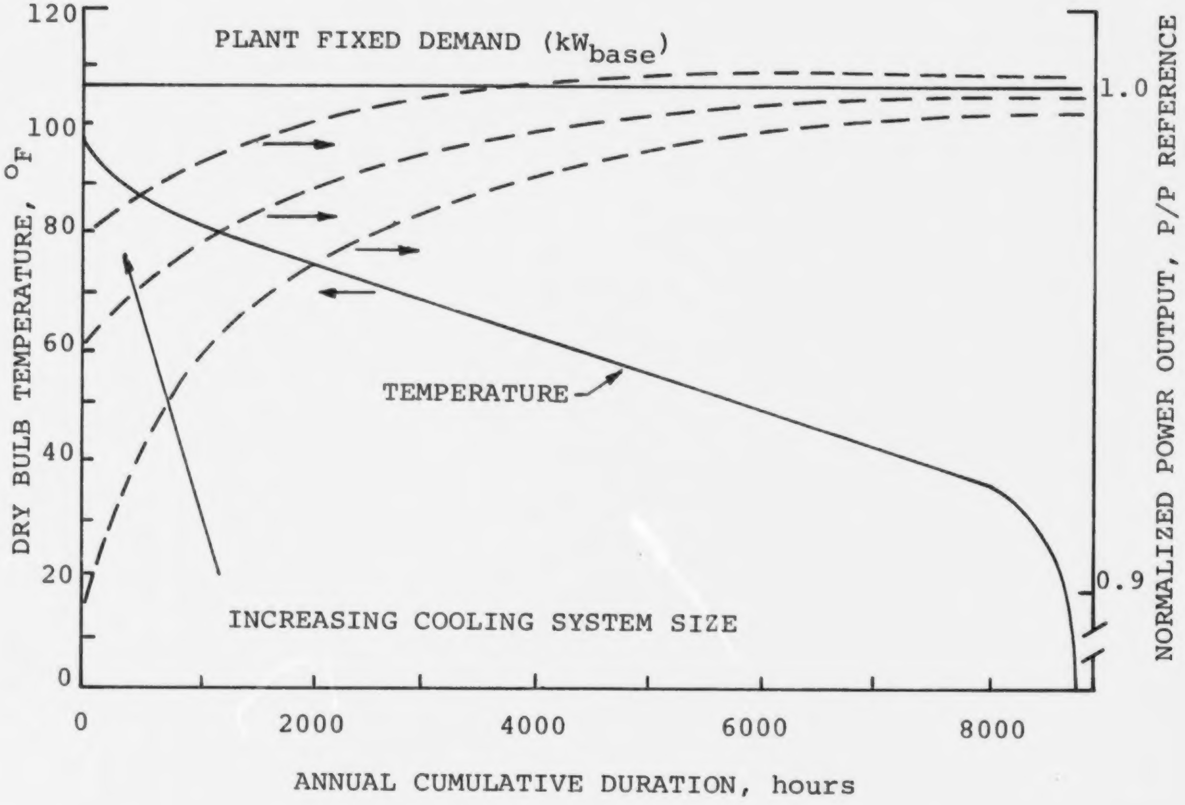

Figure 3.5. Relative performance of different size cooling systems.

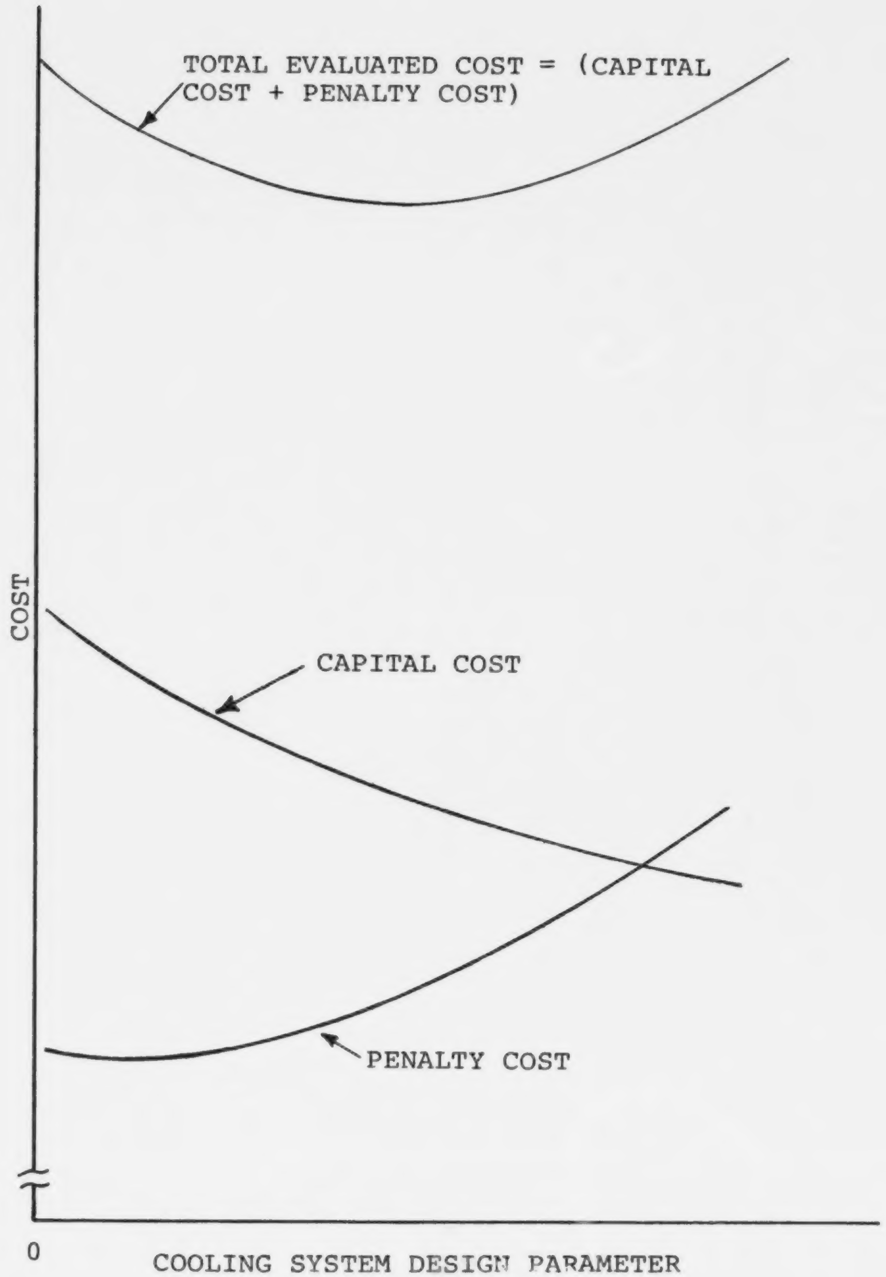

Figure 3.6. Schematic diagram of economic trade-offs and optimum selection of cooling systems.

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SECTION 4

DESIGN AND OPERATION OF CONVENTIONAL COOLING SYSTEMS

4.1 EVAPORATIVE COOLING TOWER SYSTEMS

4.1.1 General Description

In an evaporative or wet cooling tower, most of the waste heat is dissipated to the atmosphere by evaporation of a small portion of the circulating cooling water. Heated water from the plant condenser is pumped to the top of the tower's fill or packing material. The water then flows or splashes down through the fill to the water collecting basin while air sweeps through the fill area. As the water and air come in contact, a small portion of the water becomes vaporized, thus, carrying with it the latent heat of evaporation. In the process, air is humidified, and the remaining unvaporized water is cooled. The water falls by gravity through the fill, while the air flows either perpendicular to the flow of water (crossflow) or upward and parallel to the flow of water (counterflow).

Three different methods are used to provide a continuous flow of fresh air through the tower, resulting in three major tower types:

1) Mechanical Draft Cooling Towers

A mechanical draft cooling tower is one which uses a fan to move the air through the tower. The fan provides a constant volume of air flow through the tower independent of the ambient weather conditions. The fans can be either induced draft or forced draft fans, depending on whether the air is pulled or forced through the tower. For power plant application, most mechanical draft towers use induced draft fans. Air flow through the tower is varied by changing the fan motor speed and/or the pitch of fan blades. Figure 4.1 shows typical mechanical draft towers of the counterflow and crossflow types(1).

2) Natural Draft Cooling Towers

A natural draft tower is one that depends on a chimney or stack to induce air movement through the tower. Instead of a constant volume of air flowing through the tower as in a mechani-

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cal draft tower, the natural draft tower has an air flow rate which is proportional to the density difference between the ambient air and the warmer humid air in the tower. Figure 4.2 shows typical counterflow and crossflow natural draft cooling towers(1).

3) Fan Assisted Natural Draft Cooling Towers

A fan-assisted natural draft cooling tower is one that depends on both the chimney effect and the fans to move the ambient air through the tower. The fans are usually located around the periphery at the base of the tower. The fans augment the natural draft and provide a nearly constant volume flow. In addition, the air flow provided by the fans allows a substantial reduction of the tower height needed to provide the air flow through natural draft. Figure 4.3 shows typical counterflow and crossflow fan-assisted natural draft towers(2).

4.1.2 Heat Transfer

The macroscopic approach of Merkel's total heat theory has been almost universally adopted for the calculation of tower performance. Merkel's theory states that the local heat transfer taking place in a cooling tower is proportional to the difference between the enthalpy of air stream and the enthalpy of air saturated at the temperature of the water. In the following discussion, the derivation of Merkel's equation is given to provide a better understanding of the operation of a wet cooling tower. It has been shown that Merkel's equation is sufficiently accurate for practical application as compared to a rigorous solution(3).

The energy equation for a cooling tower is:

$$(C_p)_w L(\Delta T) = G\Delta H_a \qquad (4.1)$$

where:

$(C_p)_w$ = specific heat of water, J/Kg°C.

L = mass flow of water into the cooling tower, Kg/s.

ΔT = cooling range in tower, °C (see Figure 4.4).

G = mass flow rate of dry air through the system, Kg/s.

ΔH_a = change of the air enthalpy per unit mass of dry air as the air passes through the tower, J/Kg.

Equation (4.1) is applicable to any cooling device which uses the atmosphere as its final heat sink. The simplifying assumption made in Equation (4.1) is that the water flow rate remains constant in the cooling tower. This is not exactly true, because of the water loss due to evaporation. However, since the actual amount evaporated will usually be less than three percent of the circulating water flow, this assumption will introduce very little error.

The driving potential for the sensible heat transfer is the difference between the water temperature and the temperature of the air in contact with the water. The driving potential for evaporation is the difference between the concentration of water vapor in the saturated air at the water surface and the concentration of water vapor in the bulk of the air stream. This relationship can be expressed for a volume element of a cooling tower packing(3-5) as:

$$(C_p)_w L \cdot dT_w = \left[h(T_w - T_a) + K \cdot H_v \left\{ W_s(T_w) - W(T_a) \right\} \right] a \cdot dV \quad (4.2)$$

where:

$(C_p)_w$ and L are defined under Equation (4.1).

dT_w = incremental change in water temperature, ^{o}C.

h = heat transfer coefficient, $W/m^{2\,o}C$.

T_w = temperature of the water in the volume element, ^{o}C.

T_a = temperature of the air in the volume element, ^{o}C.

K = mass transfer coefficient for water vapor, Kg/m^2.

H_v = latent heat of vaporization, J/Kg of dry air.

$W_s(T_w)$ = specific humidity of saturated air at the water temperature, Kg of water vapor/Kg of dry air.

$W(T_a)$ = specific humidity of air stream, Kg of water vapor/Kg of dry air.

a = water surface area per unit volume of the cooling tower packing, m^{-1}.

dV = increment of tower packing volume, m^3.

The right side of Equation (4.2) can be rearranged to yield the following equation:

$$(C_p)_w L \cdot dT_w = K \left[\left(\frac{h}{C_p K}\right) C_p (T_w - T_a) + H_v \left\{ W_s(T_w) - W(T_a) \right\} \right] a \cdot dV \quad (4.3)$$

where:

C_p = specific heat of dry air, J/Kg°C.

The ratio h/C_pK (Lewis number) has been experimentally determined and has been found to be almost equal to one for an air-water vapor system. Using the value 1.0 for h/C_pK and rearranging Equation (4.3) gives:

$$(C_p)_w L \cdot dT_w = K \left[\left\{ C_p T_w + H_v \cdot W_s(T_w) \right\} - \left\{ C_p T_a + H_v \cdot W(T_a) \right\} \right] a \cdot dV \quad (4.4)$$

The term $(C_pT_w + H_v \cdot W_s(T_w))$ is the enthalpy of saturated air at the the water surface temperature; the term $(C_pT_a + H_vW(T_a))$ is the enthalpy of the bulk air stream. Thus, Equation (4.4) can be written:

$$(C_p)_w L \cdot dT_w = K \cdot \left[H_s(T_w) - H(T_a) \right] a \cdot dV \quad (4.5)$$

where:

$H_s(T_w) = (C_pT_w + H_v \cdot W_s(T_w))$

$H(T_a) = (C_pT_a + H_v \cdot W(T_a))$

Rearranging the terms in Equation (4.5) assuming K and a are constants and integrating over the total cooling tower packing volume gives:

$$\frac{KaV}{L} = \int_{T_{w1}}^{T_{w2}} \frac{(C_p)_w \, dT_w}{H_s(T_w) - H(T_a)} \quad (4.6)$$

The enthalpy of moist air at any dry bulb temperature, T_a, and wet bulb temperature, T_{wb}, is approximately equal to the enthalpy of saturated air having a temperature equal to the wet bulb temperature; i.e., $H(T_a) = H_s(T_{wb})$. If $H_s(T_{wb})$ is substituted for $H(T_a)$, Equation (4.6) becomes Merkel's equation:

$$\left(\frac{KaV}{L}\right)_M = \int_{T_{w1}}^{T_{w2}} \frac{(C_p)_w \, dT_w}{H_s(T_w) - H_s(T_{wb})} \qquad (4.7)$$

Figure 4.4 illustrates the water and air relationship and the driving potential which exists in a counterflow tower(4-8). This figure will be used to explain the tower cooling process and the meaning of Merkel's equation. The water operating line, AB, is fixed by the tower inlet and outlet water temperatures; and it represents the conditions of the air adjacent to the falling water surface. Since it is generally assumed that the air adjacent to the water surface is saturated at the water surface temperatures, the line, AB, is a portion of the saturation line on the psychrometric chart. The air operating line, CD, represents the bulk air conditions as the air flows through the tower with the air entering the tower at point C and leaving the tower at point D. Point C for the bulk air stream corresponds to point B for the air layer adjacent to the water surface and has an enthalpy equal to the saturation enthalpy at the entering air wet bulb temperature. Similarly point D corresponds to point A and has an enthalpy equal to the saturation enthalpy at the leaving air wet bulb temperature. The vertical segment, MN, between the water and air operating lines represents the enthalpy driving force (H_s - H), previously represented as ($H_s(T_w - H(T_a))$. The water-to-air ratio (L/G) is the slope of the air operating line as defined by Equation (4.1). The coordinate axes refer directly to the temperature and enthalpy of any point on the water operating line, AB. The corresponding wet bulb temperature of any point on the air operating line, CD, is found by projecting the point horizontally to the water operating line, AB, then vertically to the temperature axis. The cooling range is the projected length of line, CD, on the temperature scale. The cooling tower approach is shown on the diagram as the difference between the cold water temperature leaving the tower and the ambient wet bulb temperature.

The integral of the Merkel's equation (Equation (4.7)) is inversely proportional to the area ABCD in the diagram. The term $(KaV/L)_M$, known as the tower characteristic, is proportional to the relative degree of difficulty to perform a given heat transfer duty. For a given water flow rate and range, the cooling tower characteristic will decrease as the area between lines AB and CD increases. The area can be increased by increasing the approach or by decreasing the enthalpy driving force, H_s - H. A decrease in H_s - H can be achieved by increasing the air flow rate. The air flow rate must always be large enough so that line CD will not intersect line AB.

Equation (4.7) has been graphically represented as a function of water-to-air ratio (L/G), approach, range, and wet bulb temperatures. Separate charts have been prepared for each representative combination of inlet air wet bulb temperature and range(9). These charts can be used with experimentally obtained cooling tower characteristics to size the tower at a given design condition and estimate the tower performance at off-design conditions. An example of their use is shown in Section 4.1.4 where they are used to illustrate the procedure for the design of a mechanical draft tower.

4.1.3 Design and Performance Parameters

The major parameters which influence the size and performance of a cooling tower are(6): 1) cooling range, 2) approach (Figure 4.5), 3) ambient wet bulb temperature, 4) flow rate of water to be cooled, 5) flow rate of air passing through the tower packing, 6) performance coefficient of the tower packing, and 7) volume of the tower packing. The parameters over which the cooling system user has control are: 1) the cooling range, 2) the approach, and 3) the design wet bulb.

The ambient wet bulb temperature is an important factor in designing, sizing, and selecting evaporative towers. It is a controlling factor since it is the lowest temperature to which water can be cooled by the evaporative method. Selection of a proper design wet bulb temperature is, therefore, vital in determining the optimum cooling tower size. A design wet bulb temperature that is too high can result in an oversized tower; one too low can result in inadequate tower capacity, such that the power plant it serves would experience severe capacity deficits at high ambient temperatures. Current practice is to select a wet bulb temperature which is exceeded no more than one percent of the time during an annual cycle.

Once the design wet bulb temperature is established, the range and approach determine the size and, consequently, the cost of the cooling equipment. Thus, in economic evaluations of wet tower cooling systems, these variables are extensively investigated for each application. The heat rejection duty of the tower is equal to the product of the range, circulating water mass flow rate and the specific heat of water. The typical effect of range on tower size for constant heat load, ambient wet bulb, and cold water temperature is shown in Figure 4.6a(1). With a given heat load, the size of the tower increases as the range decreases. The increased capital cost for a larger tower would be compensated by better operating performance in that the lower range of this tower would achieve a lower back pressure in the turbine and, consequently, lower operating penalties over the lifetime of the plant (see Section 3 for a discussion of capital and operating costs).

The final and most important temperature consideration is establishment of the approach, the difference between the cold water temperature and the wet bulb temperature. Once the design wet bulb temperature and range have been determined, the approach fixes the operating temperatures.

The typical effect on tower size of varying the approach while holding heat load, design wet bulb, and range constant is shown in Figure 4.6b(1). With a given heat load, the size of the cooling tower required increases as the approach decreases. Of all of the variables involved, the approach can have the greatest effect upon the size and cost of the cooling tower. The closer the cold water temperature approaches the wet bulb temperature, the greater the increase in cooling tower size. For example, consider a tower designed for a 15°F (8.4°C) range and a 15°F (8.4°C) approach to a 76°F (24°C) wet bulb temperature. Decreasing the approach to 10°F (5.5°C) will increase the tower size by 50 percent. In comparison, decreasing the range from 15°F (8.4°C) to 10°F (5.5°C) will increase the tower size by only 15 percent.

As in the example described in the discussion on range, increased capital costs for larger size cooling towers are compensated for by better operating performance. In evaluating the costs of cooling systems, the investigation should include the trade-off between the capital costs and the operating costs of each design.

4.1.4 Mechanical Draft Wet Cooling Tower Design

Charts, such as that shown in Figure 4.7, can be used with experimentally obtained cooling tower characteristics provided by tower manufacturers to size a tower for a given heat duty. The empirical characteristic equation describes the relationship between the tower characteristic, $(KaV/L)_C$, and the water-to-air ratio, (L/G), for the tower as given in the following functional form:

$$\left(\frac{KaV}{L}\right)_C = c\left(\frac{L}{G}\right)^{-n} \tag{4.8}$$

where:

$\left(\frac{KaV}{L}\right)_C$ = characteristic of a particular cooling tower or cooling tower module design.

c, n = parametric constants which describe the line AB on Figure 4.7.

The tower characteristic curve for a particular cooling tower design is usually determined from test data and performance tests conducted at research facilities. The research data are then related to field performance tests for further substantiation. The values of "c" and "n" in Equation (4.8) are a function of packing design. The value of n is the slope of the characteristic curve for the packing design. Values can vary from 0.25 to 1.0. The lower values are generally characteristic of splash-type packings, and the upper limits are usually associated with high heat transfer, film-type packings. The average value of n for industrial type packings is from 0.5 to 0.6(10).

To size a tower using standard modules and to determine its performance, the following parameters in units consistent with that used to develop the empirical characteristic equation must be known about the standard module:

T_{wbs} = wet bulb temperature.

TR_s = temperature range.

L_s = water mass flow rate.

G_s = air mass flow rate.

c, n = characteristic equation parameters at T_{wbs} and TR_s.

HP_s = input power to tower fans.

The procedure requires that the experimentally determined characteristic $(KaV/L)_C$ equals the characteristic $(KaV/L)_M$ determined at the design conditions using Merkel's Equation:

$$\left(\frac{KaV}{L}\right)_M = \left(\frac{KaV}{L}\right)_C \tag{4.9}$$

With this condition satisfied, the water-to-air flow ratio, (L/G), needed to reject a given amount of heat with a corresponding range and approach can be obtained. The water-to-air flow ratio along with the air flow rate of the standard module can be used to determine the number of modules needed.

Specific information concerning the tower characteristic equation must be obtained from the tower manufacturer. This information is proprietary with each manufacturer. The manufacturer's tower characteristic graph is made available to the utility for evaluating the guaranteed performance of the tower after it has been purchased.

4.1.5 Natural Draft Wet Cooling Tower Design

The cooling process which takes place in a natural draft wet tower is identical to the process which occurs in a mechanical draft tower. The equations which describe the heat transfer process in a mechanical draft tower are also applicable to a natural draft tower. The basic difference between the towers is the way by which the air flow is established. As indicated in Section 4.1, a natural draft tower depends on a chimney or buoyancy effect to induce air movement through the tower.

As stated in Section 4.1.4, specific information concerning the tower characteristic equation is proprietary with each manufacturer. If, however, the tower characteristic is provided, the water-to-air flow ratio and the air flow rate can be determined. Thus, the basic design objective of the natural draft tower is to achieve the needed air flow rate for heat rejection. As the air flows through the tower packing, it is heated and humidified by evaporation. Both of these processes reduce the density of the air and produce a driving pressure differential called draft which in turn maintains the continuous flow of air through the tower. The magnitude of the draft is proportional to both the air density difference and the tower height and is expressed as:

$$\Delta P_d = H\ (\rho_a - \rho_e) g \qquad (4.10)$$

where:

ΔP_d = draft, N/m^2.

H = tower height, m.

ρ_a = density of the ambient air, Kg/m^3.

ρ_e = average density of the humidified air in exiting from the tower, Kg/m^3.

g = gravitational acceleration, m/s^2.

This draft must be at least equal to the flow resistances encountered by the air stream at steady state conditions. The individual flow resistances are usually expressed in terms of a loss coefficient and a velocity head(3):

$$\Delta P_i = \frac{N_i \rho_i V_i^2}{2} \qquad (4.11)$$

where:

ΔP_i = resistance to air flow, N/m^2.

N_i = loss coefficient.

ρ_i = air density, Kg/m^3.

V_i = air velocity, m/s.

i = subscript identifying location of important air flow resistances in the tower.

The total resistance to air flow in the tower requires summation of all the important flow resistances in the tower. These usually include the resistance of the packing, the frictional resistance of the internal tower shell, the resistance created by the water drops, and the resistance of the various obstructions, such as drift elminators(11-14). Thus,

$$H\ (\rho_a - \rho_e)g = \sum_{i=1}^{N} \frac{N_i \rho_i V_i^2}{2} \qquad (4.12)$$

Theoretically, as long as a density difference exists, a tower height can be selected to obtain the required draft; however, there is a practical limit on tower height due to structural and economic considerations.

Natural draft towers in the United States are constructed of reinforced concrete with the shell shaped like a hyperboloid of revolution. A cylindrical shell would work equally well; however, to produce the same amount of draft, a hyperboloid shell provides improved structural strength against wind forces and requires less material for its construction(14).

In response to the increased heat rejection required for the new generation of large electric generating stations, the manufacturers have provided larger towers. Figure 4.8 shows the trend in natural draft tower sizes in the United States since 1958. There are more than 120 natural draft towers installed or planned in the U. S.(15), mostly in the eastern half of the country.

4.1.6 Fan-Assisted Natural Draft Cooling Tower Design

In recent years, as the size of power plants increased, the size of natural draft cooling towers increased proportionally as shown in Figure 4.8. Cooling tower manufacturers and electric utilities have been looking for ways to reduce the aesthetic impact of these tower installations while retaining the advantages of natural draft towers in terms of environmental impacts of plume and drift (see Section 11). As a result the fan-assisted natural draft tower evolved; it utilizes a hyperbolic shell similar to that of the natural draft tower with motor-driven fans at the periphery of its base. Because it no longer depends on the stack height to produce all of the needed draft, the height and diameter of a fan-assisted tower can be tailored to each site, considering specific limitations of ground area and height of plume discharge.

Current design and operating experience of fan-assisted natural draft towers have been developed in Europe. In 1976 there were only 10 such towers in operation or under construction in Europe and none in the United States(2). The majority of these towers (nine) are of the conventional forced draft counterflow towers, and one is of the crossflow induced draft type.

To take full benefit of the natural draft effect of the fan-assisted tower, the fans should be controlled such that their use is minimized. Figure 4.9 shows a typical annual cycle of fan use. The fans operate at maximum power for a very short period of the year and operate at or below 50 percent of capacity for most of the year(2).

4.1.7 Description of Components and Materials of Construction Used in Wet Cooling Towers(16)

The basic components of the wet towers are: 1) tower framework, 2) water distribution system, 3) fill or packing material, 4) drift eliminators, 5) inlet louvers, 6) water collecting basin, and 7) fans. The following discussion describes the main function of each component and the materials used in construction.

4.1.7.1 Tower Framework--

The tower framework for mechanical draft towers is a structure designed on the basis of aerodynamic, structural, thermal, and economic considerations. It is designed to support the weight of the various components in the tower as well as the weight of the cooling water. The framework may be of wood or concrete but must be strong enough to withstand winds and seismic loads.

The tower framework of a natural draft tower or fan-assisted natural draft tower is usually a hyperboloid shell made of reinforced concrete. The hyperboloid shape is used because of structural and economic considerations.

4.1.7.2 Water Distribution System--

The function of the water distribution system is to provide a uniform distribution of the hot water above the fill. The distribution network can be made of treated redwood, cast iron, carbon steel, polyvinyl chloride (PVC), fiberglass, or asbestos cement. All spray nozzles are usually made of plastic.

4.1.7.3 Fill or Packing Material--

The function of the fill or packing material is to break the water into many small droplets or filaments so as to increase the air-water interface area as well as the contact time. Two types of fill are in common use: film fill which breaks the water into thin filaments and splash fill that produces small droplets. The fill material can be wood, asbestos cement, or various types of plastics. Several examples of packing configurations are shown in Figure 4.10.

4.1.7.4 Drift Eliminators--

Drift eliminators are located above the fill material. They serve as a baffle designed to cause a sudden change in the direction of the air stream. The sudden change in direction strips the water droplets from the rising air stream, thus reducing the quantity of water (drift) lost to the atmosphere. Materals used in the construction of drift eliminators are wood, asbestos cement, and various types of plastics. Typical drift eliminator configurations are shown in Figure 4.11.

4.1.7.5 Inlet Louvers--

The inlet louvers provide a uniform air flow into the tower. Their design includes proper slope, spacing and width to prevent water losses and to minimize icing problems during the winter. Construction materials are usually treated redwood, asbestos cement or plastics.

4.1.7.6 Water Collecting Basin--

The cooled water falls through the fill and is collected at the bottom of the cooling tower in a basin from which it is pumped back to the condenser. The basin is constructed from concrete.

4.1.7.7 Fans--

In mechanical draft cooling towers, a fan provides the desired flow of air through the tower. The fan can be located at the top of the cooling tower above the drift eliminators or at the bottom of the cooling tower. In the former case, the induction principle is applied and the fan pulls air through the fill and the drift eliminators. In the latter case, which usually applies to small towers, the fan pushes air up the tower through the fill and the drift eliminators. Blades are made of fiberglass covered with a polyester resin or aluminum coated with an epoxy or other synthetic resin selected for its corrosion and erosion resistance properties. Blade diameters in conventional U. S. practice range from 28 to 80 feet.

4.2 COOLING PONDS

4.2.1 General Description of Cooling Ponds

Cooling ponds are man-made bodies of water or natural lakes used for dissipating waste heat from power plants. Heat dissipation from the pond surface is accomplished by radiation, conduction, convection, and evaporation. Since a cooling pond does not have forced air or forced water motion, it is less efficient than a cooling tower as described in Section 4.1. The low rate of heat transfer requires that cooling ponds have large surface areas. The rule-of-thumb values often cited for pond surface requirements range from 1 to 3 acres per megawatt of electric output.

Cooling ponds are generally considered economically attractive for power plants sited in locations where the cost of land is low and conducive to the construction of the pond, and the soil is relatively impervious. One of the advantages of a cooling pond worth noting is its potential use for other purposes which may be incorporated in the design of the pond.

The following list presents the major advantages and disadvantages of cooling ponds(17):

Advantages

1. Have reasonable construction costs where land costs and soil conditions permit
2. Serve as settling basin for suspended solids
3. Need no makeup for extended periods
4. Provide possible recreational area
5. Can be stocked with fish species that are able to tolerate the warmer waters (Ponds can also serve as an area for aquaculture or fish farming.)
6. Serve as river control to minimize flooding or increase minimum flow
7. Need very little maintenance
8. Have low pumping power requirements

9. Have a high thermal inertia (Water temperature at the pond intake will not reflect short-term changes in meteorological conditions or plant loading.)

Disadvantages

1. Require large land area and deny use of this land for other useful purposes
2. Require soil basin of low permeability or liners
3. Tend to concentrate dissolved solids which may leach into an underground water source
4. May lead to fogging and icing in adjacent areas
5. Serve as collecting area for wind-blown debris
6. May deny runoff waters to former users below the pond sites

4.2.2 Classification of Cooling Ponds

Cooling ponds are usually classified by depth as well as flow pattern(17). A pond is generally considered to be shallow if its depth is on the order of 8 to 20 feet (2.4 to 6.1 meters). Cooling ponds which exceed 20 feet (6.1 meters) are characterized as deep ponds. Both types can be further classified according to their flow pattern to be described later in this section.

Cooling ponds can also be classified according to their intended usage as single purpose (heat rejection primarily) or multipurpose (heat rejection, recreation, irrigation, etc.). These classifications are important in the licensing procedure for power plants designed to use cooling ponds, especially in the definition of the consumptive water use of the pond(18-21).

4.2.2.1 Shallow Ponds--

Shallow ponds are constructed primarily for heat dissipation. These ponds are subdivided into "flow through" or "slug flow" and "completely mixed" types. This distinction depends heavily on the pond shape and pond outlet design.

Completely mixed ponds are assumed to have a uniform temperature throughout. Conditions promoting such behavior are: 1) a sufficient depth to allow wind-induced circulation as well as circulation induced by plant pumping, 2) a small enough depth to avoid stratification, 3) a rounded perimeter to permit the heated water to mix easily into all of the pond,

4) a discharge located away from the pond shore, and 5) long retention time.

Flow-through (or slug flow) ponds are generally long and slender with inlet and outlet at opposite ends, narrow width to minimize wind mixing, large width to depth ratio, or low velocity to minimize vertical velocity gradients. Thus, a flow-through pond provides more rapid cooling, but it is more expensive to build than the completely mixed pond.

4.2.2.2 Deep Ponds--

Deep ponds are usually constructed for multiple uses or are natural ponds which have multiple uses. Deep ponds are usually well-stratified thermally. Deep ponds are further classified into three categories: 1) horizontally-mixed, 2) flow-through, and 3) internally-circulating. In the first two, the water temperature distribution is dominated by the natural hydrological and meteorological conditions; in the latter, the natural conditions are augmented by the design of the intake and discharge. As the name implies, the horizontally-mixed ponds exhibit uniform temperature within each horizontal plane. Reservoirs where the heat burden is less than 0.25 MWe per acre and the discharge rate to pond capacity is small will generally approximate a horizontally-mixed pond.

For discharges with high flow volume outputs relative to total reservoir capacity, the pond is classified as flow-through. In this type, horizontal gradients become important.

In internally-circulating ponds, the heat burden is high, and the effects of meteorological conditions are no longer dominant.

4.2.3 Heat Transfer in Cooling Ponds

4.2.3.1 Mechanisms of Heat Transfer--

The heat transfer mechanisms occurring at the surface layer of a cooling pond include the following: 1) incoming shortwave solar radiation, Q_s, 2) incoming longwave atmospheric radiation, Q_a, 3) solar radiation reflected from the pond surface, Q_{sr}, 4) atmospheric radiation reflected from the pond surface, Q_{ar}, 5) longwave back radiation from the pond surface to the atmosphere, Q_{br}, 6) heat loss due to evaporation, Q_e, and 7) heat loss or gain due to conduction and convection of air, Q_c. These mechanisms are depicted in Figure 4.12(22).

The intensity of incoming solar radiation striking the water surface at a given location depends on the altitude of the sun and on the amount of cloud cover. The longwave atmospheric radiation comes from the gases, notably water vapor, carbon dioxide and oxygen, in the atmosphere and depends on both the altitude and amount of cloud cover. Not all of the incoming radiation reaching the water body passes through the water surface. These incoming solar and atmospheric radiations are independent of water temperature.

The major heat losses at the pond surface are due to back radiation, evaporation, and conduction-convection. The magnitude of these losses is dependent on the water surface temperature. The back emitted radiation is proportional to the fourth power of the absolute temperature of the surface. The heat convection to the atmospheric air above the surface is proportional to the difference of the water temperature and the air temperature. The heat loss due to evaporation is proportional to the difference in saturation vapor pressure at the water surface temperature and the water vapor pressure in the ambient air above the surface.

4.2.3.2 Net Rate of Heat Transfer Across a Cooling Pond Surface--

The steady state net rate at which heat is transferred across the water surface to the atmosphere is as follows:

$$Q = (Q_{br} + Q_c + Q_e) - (Q_s + Q_a - Q_{sr} - Q_{ar}) \quad (4.13)$$

$$= (Q_{br} + Q_c + Q_e) - Q_R \quad (4.14)$$

where:

$Q_R = (Q_s + Q_a - Q_{sr} - Q_{ar})$ and is the net thermal radiation absorbed by the water body.

The other quantities are as defined in Section 4.2.3.1.

There are a number of semi-empirical models available for the calculation of the basic components in Equation (4.13) or Equation (4.14), such as the Edinger-Geyer(22), Brady et al.(23), Hogan et al.(24), and Thackston-Parker(25). Each of the models, however, can be reduced to a simple form which states that the rate of heat loss to the overlying air is a function of heat transfer coefficient, K, and the driving temperature, that is,

$$Q = KA(T_s - T_e) \quad (4.15)$$

where:

K = heat transfer coefficient.

A = surface area.

T_s = water surface temperature.

T_e = equilibrium temperature of water surface.

The value of K is a function of wind speed and air and water surface temperatures. The equilibrium temperature T_e is defined as the surface temperature $T_s = T_e$ for which $Q = 0$ under steady environmental conditions, i.e., without the addition of power plant waste heat.

In cooling ponds, the forced evaporation loss, i.e., evaporation loss due to the addition of power plant waste heat, accounts for 40 to 80 percent of the waste heat dissipated. The wind speed and water temperature are the major parameters in determining what fraction of the total loss is evaporation. The remaining waste heat, 60 to 20 percent, is lost to the atmosphere primarily by convection and longwave radiation from the pond surface temperature. One other element in the pond heat balance is the heat transfer to the ground; it has been estimated to be between 0.5 - 2.5 Btu/ft^2-hr-$^\circ$F(17).

4.2.4 Design and Performance Parameters for Cooling Ponds

The parameters which affect the design and performance of cooling ponds include those directly affecting heat transfer and those affecting the circulation pattern of water flows. The circulation pattern affects the water temperature and indirectly affects the heat transfer from the pond surface. In addition to the information presented here, modeling of cooling pond water consumption is discussed in Section 11.3.

4.2.4.1 Parameters Affecting Heat Transfer--

As was discussed in Section 4.2.3, the parameters which affect the surface heat exchange of the cooling pond include the following: 1) latitude, 2) time of year, 3) solar radiation, 4) cloud cover, 5) air temperature, 6) relative humidity, 7) wind speed, and 8) water surface temperature.

The first four parameters and the last one affect the net thermal radiation which is absorbed by the water body. The last four parameters affect the pond surface heat transfer mechanisms (back radiation, conduction-covection, and evaporation) in the following manner:

Back Radiation: $Q_{br} \sim T_s^4$

Convection: $Q_c \sim (T_s - T_a)$

Evaporation: $Q_e \sim (e_s - e_a)$

The symbols used in the above proportional (~) expressions are:

T_s = pond surface temperature, ^oK.

T_a = air temperature (dry bulb), ^oK.

e_s = saturation vapor pressure at T_s, mm Hg.

e_a = water vapor pressure in ambient air, mm Hg.

4.2.4.2 Parameters Affecting Water Circulation Patterns--

Based upon actual observation of prototype ponds, Ryan(26, 27) summarized the major parameters affecting pond circulation patterns. They are: 1) entrainment of pond water by plant effluent, commonly called "entrance mixing", 2) pond shape, 3) configuration of the cooling water intake and water body outlet, 4) wind effects, and 5) density-induced currents. Each factor will be discussed briefly below.

1) Entrance Mixing

Initial mixing strongly affects pond performance in transferring heat. This mixing depends mainly on the design of the outfall from the condenser discharge, the densimetric Froude Number of the influent to the pond, as well as the shape of the pond. The densimetric Froude Number is the criterion by which the type of flow, tranquil or rapid, is determined. Tranquil flow occurs when the Froude Number is less than unity and rapid flow when it is greater than unity. Heat is dissipated more rapidly from a pond with a higher surface temperature than from the same pond with a lower temperature. If the outfall promotes entrance mixing, the pond will have a lower average temperature and approximate a completely mixed pond. Because of this, a completely mixed pond requires more surface area than a flow-through pond to reject the same head load.

2) Shape of the Pond and Effect of Depth

Pond shape is the most significant variable in determining hydraulic characteristics. A round or square surface pond is less preferred than a long slender pond due to eddy formation at stagnation points and possible flow separation. Wind and density-induced currents always complicate the effect of pond shape.

Occasionally, stream distribution equipment is used to increase the active or participating area for cooling. Common techniques involve modifying the outlet to a fan shape with a grating across it, or constructing a stream distribution levee to force the influent to cover a greater pond area.

The deeper the pond, the longer the response time to weather or plant loading changes. Pond storage capacity should at least equal the volume circulated in 24 hours to take advantage of night cooling, as well as to even out temperatures resulting from changes in plant loading. It is commonly accepted that a depth of 8 to 12 feet is necessary to prevent large diurnal variations in temperature. For depths less than 5 feet, there is a tendency for accelerated aquatic growth. If a pond is too shallow, wind-induced mixing will likely predominate, preventing the formation of density-induced currents which disperse heat into outlying regions of the pond. In cases where the cooling pond acts as a storage reservoir for make-up water, an additional constraint is generally imposed on pond depth. The normal operating depth should be at least 5 feet (1.5 meters) plus the maximum expected drawdown to allow the pond to function effectively.

3) Location and Design of Intake and Outfall Structures

In general, the discharge will be located at the surface with an initial densimetric Froude Number less than unity to reduce entrainment. The intake should be located as deep as practicable to avoid recirculation of influent water and to take advantage of the pond's cooling capacity as weather and plant loading conditions change. Ryan recommends building a skimmer wall, if locating the intake in deep water is not feasible. If the discharge is directed away from the intake at a reasonable velocity, i.e., 2 to 3 feet per second (0.6 to 0.9 meters per second), Kirkwood, et al.(28) estimates that separation of discharge and intake structures by about 40 percent of the pond length is adequate to prevent recirculation. Local wind effects should also be considered.

4) Wind Effects

A pond should be designed so that the prevailing wind during the summer is directed from the condenser intake to the condenser discharge, thus avoiding recirculation during the pond's most critical season. The most common effect of wind is the vertical mixing caused by wind-generated waves. Only a very shallow pond or the topmost layer of a deeper pond is directly affected. Wind-induced currents are a secondary effect which forces warmer waters into outlying regions of the pond and, thereby, increases its effective area. A third effect is the piling up of warm water by the wind on the pond shore. Tilting of the heated layer-cold pond water interface may be caused by the wind and result in increased recirculation problems.

5) Density-Induced Current Effects

Density differences within the warm plume and between the plume and the pond water will cause lateral spreading. In general, wind-induced currents are an order of magnitude greater than those induced by density disparity. Density-induced currents are, in turn, an order of magnitude greater than those induced by pumping. As noted above, density-induced currents assist in improving the active area of a cooling pond.

4.2.5 Design and Size of Cooling Ponds

4.2.5.1 Design of Cooling Ponds--

The design of a cooling pond is affected by the local climatic, topographic, and hydrological characteristics of the site. The construction of cooling ponds is normally limited to placing dikes or low dams to take advantage of natural topography. Excavation is unrealistic for large ponds; the cost of excavating an entire pond would normally be prohibitive. Presently, the design of ponds is still very much of an art. Much more work remains to be done in defining appropriate criteria and in selecting design procedures.

One example of pond construction using dikes and dams is that for the Cholla Plant in Holbrook, Arizona(29). The pond, shown in Figure 4.13, was formed by placing dikes on three sides. The dikes have a maximum height of 14 feet (4.2 meters) and required 265,000 cubic yards (202,619 cubic meters) of fill. The pond has a surface area of 380 acres (154 H) with an average depth of 9 feet (2.7 meters) and serves a plant of 125-MWe rated capacity.

4.2.5.2 Sizing of Cooling Ponds--

Mathematical models which adequately encompass the entire range of features for the description of pond performance are not available. Hence, experience and simplified analysis provide the primary basis for the engineering design of cooling ponds(29).

The most simplified models are the completely mixed flow model and the slug flow model. These two flow models, combined with empirical correlations for surface heat exchange coefficient and equilibrium temperature, give a rough estimate of the pond size required to reject a given heat load.

1) Completely Mixed Pond

Since the completely mixed pond has a nearly uniform temperature, it follows that the drop in temperature from the plant discharge to the pond temperature must take place over a small portion of the pond. For such a condition to exist, the size of the pond must be large and the mixing effective.

The energy balance for the condenser and pond require that:

$$\rho C_w W(T_h - T_c) = KA(T_c - T_e) \qquad (4.16)$$

where:

ρ = density of circulating water.

C_w = specific heat of water.

W = volumetric flow rate of circulating water.

T_h = hot water temperature leaving the condenser.

T_c = cold water temperature out of the pond (= pond surface temperature, T_s in Equation (4.15)).

K = surface heat exchange coefficient.

A = pond area.

T_e = equilibrium temperature of the pond.

From Equation (4.16) the required surface area for a completely mixed pond is:

$$A = \frac{\rho C_w W\ (T_h - T_c)}{K\ (T_c - T_e)} \qquad (4.17)$$

2) Slug Flow Pond

Most man-made ponds are more closely represented by a slug flow model. The energy balance for the simplified slug flow model is:

$$\rho C_w W \cdot dT_w = -K\ (T_w - T_e) \cdot dA \qquad (4.18)$$

Integration of Equation (4.18) gives the classical exponential decay equation for constant T_e, ρ, C_w, and W:

$$\frac{T_c - T_e}{T_h - T_e} = \exp\left(-\frac{KA}{\rho C_w W}\right) \qquad (4.19)$$

Solving for the area of the pond gives:

$$A = \left(\frac{\rho C_w W}{K} \right) \ln \left(\frac{T_h - T}{T_c - T_e} \right) \qquad (4.20)$$

Equations (4.17) and (4.20) must be used in conjunction with correlations for the heat exchange coefficient, K, and equilibrium temperature, T_e, such as those proposed by Brady et al.(23). Brady's correlations are:

$$T = \frac{T_s + T_d}{2} \qquad (4.21)$$

$$\beta = 0.255 - 0.0085T + 0.00204T^2 \qquad (4.22)$$

$$f(u) = 70 + 0.7\,u^2 \qquad (4.23)$$

$$K = 15.7 + (\beta + 0.26) \cdot f(u) \qquad (4.24)$$

$$T_e = T_d + \frac{Q_s}{K} \qquad (4.25)$$

where:

T = average temperature, °F.

T_d = dewpoint, °F.

T_s = water surface temperature, °F.

β = slope of the saturated vapor pressure curve, mm Hg/°F.

$f(u)$ = wind speed function, Btu/ft^2-day-mm Hg.

u = wind speed, mph.

Q_s = gross solar radiation, Btu/ft^2-day.

K = surface heat exchange coefficient, Btu/ft^2-day-°F.

To facilitate computation of K, a design chart has been prepared by Brady et al. and is given in Figure 4.14. This figure allows direct determination of K for the given wind speed and the average temperature, T. The dew point, gross solar radiation, and wind speed for different regions of the United States can be found in the "Climatic Atlas of the United States"(30).

4.3 SPRAY CANALS

4.3.1 General Description

The power spray ponds or canals are extensions of cooling ponds and cooling tower technologies. Cooling is obtained primarily by spraying water from a pond or canal into the ambient air, whereby water is evaporated to effect cooling of the water. The purpose of spraying the water is to increase the water-to-air contact area. The result is a significantly increased heat transfer rate per unit area of pond surface. Thus, the land requirements for spray systems are reduced considerably as compared to those of simple pond systems.

The spray system can be designed as a fixed-pipe pond configuration called a spray pond or as a floating-module canal system called a spray canal. Spray ponds are generally used for small heat rejection requirements, such as the ultimate heat sink for nuclear power stations, whereas spray canals are generally used for power plant waste heat rejection. An example of a spray pond system is the ultimate heat sink for the Rancho Seco Nuclear Power Plant(31). The discussion which follows is primarily concerned with spray canals.

The floating spray system can use any one of a number of different, commercially available modules. The spray modules are anchored in the discharge canal or pond. Each module is complete with a float-mounted pump and spray heads. One such module is shown in Figure 4.15. The module consists of four spray nozzles mounted on a 120-foot length of pipe. The entire assembly floats in the water with the spray nozzles above the water surface. The module is equipped with a 75-horsepower motor and a 10,000-gpm capacity pump. Modules are placed in a canal with the axis of each module parallel to the stream flow, also shown in Figure 4.15.

Spray canal cooling is a relatively new cooling concept which is currently in use at a small number of power plants. The performance and cost of the spray systems are competitive with wet cooling towers. The possibility of using them, however, will depend on the availability of land and the cost at the site, since the construction of the canal is one of the major cost components.

4.3.2 Heat Transfer - Performance of Spray Module

Heat transfer from a spray canal is primarily accomplished through evaporation and convection. Radiation modes of heat transfer, such as those affecting a cooling pond, are negligible because of the small canal surface.

Since the operation of a spray canal is thermodynamically similar to an evaporative cooling tower, the module performance can be described by an equation identical to Merkel's equation. This performance equation, as applied to spray modules, is called the $\overline{Ntu}$-equation:

$$\overline{Ntu} = \int_{T_c}^{T_h} \frac{C_w dT_w}{H(T_w) - H(T_{wb})} \tag{4.26}$$

where:

$\overline{Ntu}$ = number of heat transfer units, dimensionless.

C_w = specific heat of water.

T_c = sprayed water temperature (temperature of the sprayed and cooled water before it re-enters the canal water body).

T_h = canal water temperature at spray nozzle intake.

$H(T_w)$ = enthalpy of saturated air at water temperature, T_w.

$H(T_{wb})$ = enthalpy of saturated air at local wet bulb temperature in the spray field, T_{wb}.

The derivation of Equation (4.26) is given in Reference 32; it is similar to that given in Section 4 for evaporative towers.

In the derivation of Merkel's equation for towers, the energy balance on the air and water for a spray yields:

$$\frac{\Delta H}{\Delta T_w} = C_w \frac{L}{G} \tag{4.27}$$

where:

ΔH = change of air enthalpy per unit mass of dry air as the air passes through the spray field.

ΔT_w = cooling range of spray.

$\frac{L}{G}$ = liquid (water) to gas (air) ratio, dimensionless.

In the case of an open spray, however, L/G is not well defined because there is no control over the air flow. As a result, an average local wet bulb temperature inside the spray field must be used in the evaluation of the Ntu.

The number of transfer units can be determined in principle from the average dynamic and thermodynamic behavior of droplets. In practice, $\overline{\text{Ntu}}$ is obtained either from experiments on a single module or by calculations from system performance using the approximate $\overline{\text{Ntu}}$ equation given below(33,34):

$$\overline{\text{Ntu}} = \frac{C_w \ (T_h - T_c)}{\left[\frac{H(T_h) + H(T_c)}{2}\right] - H(T_{wb})} \tag{4.28}$$

where:

T_{wb} = local wet bulb temperature of air inside the spray field.

$H(T_h)$ = saturation enthalpy of air at T_h.

$H(T_c)$ = saturation enthalpy of air at T_c.

4.3.3 Design and Performance Parameters

The design parameters to be considered in sizing spray canal systems for a specific heat load using standard modules are: 1) cooling range and water flow rate, 2) approach to the wet bulb temperature, 3) ambient conditions (dry and wet bulb temperatures, wind speed and wind direction), and 4) number of modules per pass.

The wet bulb temperature, cooling range, and approach affect the canal performance in a similar manner as in wet cooling towers. The extent to which ambient wind conditions affect a spray system's performance depends on the volume of air passing through the spray region. High wind speeds permit more efficient heat transfer to the atmosphere, whereas low wind speeds hinder effective interaction of the spray and ambient air as illustrated in Figure 4.16. These data were obtained experimentally by Hoffman and are presented in Reference 34. Wilson(36), using the same experimental data as Hoffman, found a maximum in the performance curve of $\overline{\text{Ntu}}$ versus wind speed in the 9 to 12 mph range. Wilson suggests that the reduction in performance at higher wind speed is due to the deformation of the spray umbrella. The commonly used design wind speed is 5 mph.

For optimum thermal performance, a spray system canal should be placed perpendicular to the prevailing summer or design wind direction. A long, narrow canal that minimizes recirculation will perform better than a wide canal with many spray module units in the pass. Figure 4.17 shows three possible canal arrangements for spray cooling systems(37).

4.3.4 Spray Canal Design

There are two commonly used design approaches for sizing a spray canal system and calculating its off-design performance. A review of the different methods is given by Ryan(35), and Ryan and Myers(34). Each method is based on a performance model which consists of:

1. A model for the thermal efficiency of a single module as a function of water temperature, wet bulb temperature, and wind speed
2. A model which relates the individual module performance to the canal performance

4.3.4.1 Canal Design Using System Model--

The system model assumes the water flows in parallel patterns without transverse mixing between each row of modules; that is, each row of modules is treated as a separate channel. A fraction of the flow in the channel is pumped through the nozzles of each module. The water is cooled and remixed with the remaining flow in the channel. The mixed flow then proceeds to the next module.

The analysis begins with the condenser discharge end of the canal where the water temperature, wind speed, and local wet bulb temperature of the first module in the first row are known. The air flow is assumed to be perpendicular to water flow (Figure 4.17). This condition can be accomplished in design by laying out the canal such that the direction of water flow is perpendicular to the prevailing wind at the site. The temperature of the sprayed water is obtained from a module performance model, and the temperature of the water leaving a pass is obtained from the ratio of pumped flow to channel flow. As the air flows across the modules, the local wet bulb temperature increases from the ambient wet bulb temperature as a result of heat and mass transfer from the upwind modules. An empirical correction factor, i.e., an increase in wet bulb temperature of $1^{O}F$ to $2^{O}F$, is used to account for this effect.

Referring to Figure 4.18, the steady state canal energy balance for the ith pass requires that:

$$L \left[T_{i+1,n} - T_{i,n}\right] = NS \left[(T_c)_{i,n} - T_{i,n}\right] \qquad (4.29)$$

where:

L = amount of water flow in the canal, lb_m/hr.

$T_{i+1,n}$ = mixed water temperature entering the (i + 1)th pass (leaving the ith pass), ^oF.

$T_{i,n}$ = mixed water temperature entering in the ith pass, ^oF.

N = number of modules (rows) per pass.

S = amount of water sprayed by each module, lb_m/hr-module.

i = ith pass number.

n = module row number counting from the upwind side.

$(T_c)_{i,n}$ = temperature of sprayed and cooled water from the module in the ith pass and nth row, ^oF.

Solving for $T_{i+1,n}$ from Equation (4.29):

$$T_{i+1,n} = \left[1 - N(\frac{S}{L})\right] T_{i,n} + N(\frac{S}{L}) (T_c)_{i,n} \qquad (4.30)$$

The temperature $(T_c)_{i,n}$ can be obtained from module performance correlations provided by manufacturers. With that, the variables in the righthand side of Equation (4.30) are known for each module of the first pass, and the canal water temperature leaving each module of the first pass, $T_{1,n}$ (n=1, 2,......N) can be calculated. The average mixed canal water temperature entering the second pass is calculated as follows:

$$(T_{av})_2 = \frac{1}{N} \sum_{n=1}^{N} T_{2,n} \qquad (4.31)$$

The procedure is repeated until the mixed canal water temperature leaving the last pass is equal to the design cold water temperature, T_c. The design calculations are completed and the number of passes required is determined.

The above design procedure requires proprietary information concerning module performance curves and wet bulb temperature correction factors. To circumvent the difficulty of obtaining proprietary design information, canal system performance curves supplied by a manufacturer can be used to construct simplified design curves, such as the one shown in Figure 4.19. This figure was developed by the Tennessee Valley Authority and presented in Reference 34.

The use of the design curves in Figure 4.19 for determining the number of modules required to dissipate a given heat load is illustrated as follows. Consider a plant with a cooling water flow of .5 x 10^6 gpm, a hot water temperature of 100°F, and a condenser cooling range of 15°F. Other design conditions are: cold water temperature is 85°F, wind speed is 5 mph, and wet bulb temperature is 60°F.

Referring to Figure 4.19, the number of sprays per million gpm for water temperatures of 100°F and 85°F are 245 and 453, respectively. Since the design water flow rate is 0.5 x 10^6 gpm, the total number of modules is equal to: (453 - 245) x 0.5 = 104 modules, for a canal using 4 rows per pass.

4.3.4.2 Canal Design Using $\overline{\text{Ntu}}$ Model--

The same procedure described in the previous section can be used in the design of a spray canal incorporating the $\overline{\text{Ntu}}$ module performance model and associated wet bulb temperature corrections. In numerical form, the $\overline{\text{Ntu}}$ model is as follows:

$$\overline{\text{Ntu}} = \frac{C_w \, (T_{i,n} - T_{i+1,n})}{\left[\frac{H(T_{i,n}) + H(T_{i+1,n})}{2}\right] - H(T_{wb})} \qquad (4.32)$$

Several investigators have obtained empirical correlations of $\overline{\text{Ntu}}$ versus wind speed. An example is the Hoffman model given in Figure 4.16. A wet bulb temperature correction of 1°F (0.56°C) increase is suggested to account for air-vapor interference in each of the downwind rows.

For the same design conditions as the example given in the previous section, the number of modules determined by Ryan and Myers(34) using Hoffman's $\overline{\text{Ntu}}$ model is 112. The result is very close to that obtained by the empirical design curves (Figure 4.19). It was demonstrated that designs for the same case using other models, however, have shown a variation in the number of modules by a factor of two. The large variation is caused by the dependence of performance models on empirical factors obtained from relatively small systems (1 to 100 modules). Thus, the design of large systems with 400 modules or more using these models should be done with caution.

4.3.5 Mechanical Design of Spray Modules(38)

A floating spray module consists of a pump and motor, manifold, floating platform, and nozzles. Continuous exposure to highly humid conditions requires special design precautions. The motor is one of the key components in the operation of the system, and normal fan-cooled motors have been the source of a major operating problem for spray modules. Even with special seals and covering shrouds, water entering the motor has caused difficulties.

Use of a completely sealed water-cooled motor appears to have solved the problems associated with this highly humid condition. The motor must have a continuous spray of water to assure long life, and the spray pattern from the nozzles should be designed to provide cooling of the motor. Corrosion resistant coatings should be used to protect the casing from corrosion which could lead to leakage into the motor windings or bearings.

Axial flow propeller pumps are used for spray nozzle coolers. These are suitable for spray cooling applications, because of their relatively high efficiency at low head and high flow operating conditions. This high efficiency requires that close tolerances be used throughout the pump design. Also, straightening vanes are used to ensure uniform flow conditions into the propeller. A typical motor-pump assembly(39) is shown in Figure 4.20.

The manifold system must be designed to distribute the water to the nozzles effectively while maintaining a low head loss. As with the pump, the manifold system should be well protected against corrosion. Fabrication with stainless steel or other corrosion-resistant materials is recommended in certain applications; otherwise, effective protective coatings should be used. A typical manifold system is shown in Figure 4.15.

In addition to supporting the primary structure, the floats should be sized so that they provide a stable working platform for maintenance and repair. The float should be completely filled with a closed-cell polyurethane foam to provide a secondary flotation system in the event of shell failure. If the float is made of fiberglass, an internal steel structure must be incorporated into the float design to ensure that the fiberglass is not required to carry the structural loads. Figure 4.20 shows a flotation system attached to the pump-motor system.

4.4 DRY COOLING TOWER SYSTEMS

4.4.1 General Description of Dry Tower Cooling Systems

Dry cooling towers generally employ finned-tube heat exchangers to reject heat by circulating water inside the tubes and by passing the atmospheric air over the outside tubes and fin surfaces. Typical kinds of finned-tube construction are shown in Figure 4.21(40). In contrast to the wet cooling systems previously described, the heat transfer mechanism is convective heat transfer rather than heat and mass transfer between the water being cooled and the cooling air. The absence of evaporative heat exchange eliminates the make-up water requirement and the formation of vapor plumes which constitute the major disadvantages of wet cooling systems.

Dry towers can be of the mechanical draft or natural draft type. In a mechanical draft tower, ambient air is induced or forced by fans to pass over the heat transfer surface. In mechanical draft towers, air flow is controlled by use of either variable fan speeds or variable pitch blades. The natural draft tower depends on the air density difference in the atmosphere and in the tower to produce the buoyancy force for inducing the air flow. The air flow rate can be controlled by the use of louvers or dampers.

Various studies(41-44) have indicated that dry tower cooling systems have both high capital cost and severe operating penalties. The high capital cost results from the need for extensive finned-tube heat exchanger surface while the operating penalties result from the high condensing temperatures experienced during peak ambient conditions. Because of the high capital and operating costs, dry tower systems are not widely used in the power industry at the present time. Only a relatively small number of existing or new power plants are currently employing dry cooling systems as listed in Table 4.1(45,46). However, it is anticipated that dry cooling, especially in combination with wet cooling, will become more prevalent in the near future for power plant application as available water for evaporative cooling systems becomes limited and/or costly(21,41,42,44).

4.4.2 Types of Dry Cooling Systems

There are two alternative dry cooling systems which employ dry cooling towers for power plant applications. These are the direct dry cooling system and the indirect cooling system.

4.4.2.1 Direct Dry Cooling System--

The direct dry cooling system, alternatively called the direct condensing dry cooling system, is shown schematically in

Figure 4.22. In this system, the extended surface air-cooled heat exchangers of the dry tower serve to transfer waste heat to a heat sink and as a condenser in which the turbine exhaust steam is condensed directly on the inside tube surface. Large ducts are used to transport the exhaust steam to the heat exchanger coils.

After the steam condenses in the dry tower, the condensate is pumped back to the boiler feed circuit. The cooling system components are under vacuum, and provision is made for extraction of non-condensable gases. To save space and to minimize the length of exhaust steam ducting, and, consequently, the pressure drop in the ducts, the air-cooled condenser (dry tower) for small power plants can be installed on the roof of the turbine building. The present direct dry cooling systems utilize mechanical draft exclusively to produce the required air flow.

The finned tubes in the dry tower are generally laid out in chevron (ΛΛ-shape) patterns in a parallel-flow, a counterflow arrangement or a combination of the two as shown in Figure 4.23(45).

In the parallel-flow arrangement, the steam flows downward from the headers at the top. The pressure drop along the inside of finned condenser tubes is accompanied by a temperature reduction in the saturated steam. As the steam condenses in the tube, continued cooling of the condensate in the lower part of the tube tends to result in sub-cooling of the condensate. This increases oxygen absorption with attendant corrosion problems, and at ambient temperatures below 32°F (0°C), it can lead to freezing of the condensate.

In the counterflow arrangement, the exhaust steam enters at the bottom and flows upward against the downward flowing condensate. This arrangement eliminates the condensate subcooling problem, but provides reduced heat performance. To combine the advantages of both arrangements, current designs use a combination of the two, wherein the condensation of the final fraction of steam takes place in a counterflow section.

The world's largest direct dry cooling system for power plant application is the one constructed for the 330-MWe minemouth power plant of the Pacific Power & Light Company and the Black Hills Power & Light Company at Wyodak, Wyoming. The air cooled condenser arrangement for this station is shown in Figure 4.24(47). This system began operation in 1978.

4.4.2.2 Indirect Dry Cooling System--

There are two variations for the indirect dry cooling system. One of the indirect systems utilizes a spray or contact condenser. This system is often referred to as the Heller System(44,45,48) because it was first proposed by Dr. Lazlo Heller at the World Power Conference in Vienna in 1956. The other arrangement uses a surface condenser.

The Heller System is shown in Figure 4.25. Here the steam leaving the turbine is condensed by mixing with cooling water in a direct contact condenser. A typical direct contact condenser is shown in Figure 4.26(49). A portion of the condensate/cooling water mixture, equivalent in mass flow rate to the turbine exhaust steam, is returned to the boiler feed circuit, while the balance is circulated through the dry tower heat exchanger. The cold water returning from the dry tower is then sprayed again into the condenser for the condensation process. The circulating water flows in a closed circuit so that no water is lost due to drift and evaporation.

The indirect dry cooling system with a surface condenser is shown in Figure 4.27. In this system, the cooling water circuit and the steam/feedwater circuit are completely separated. Turbine exhaust steam condenses on the outside of the condenser tubes, and the condensate is pumped back to the boiler feed circuit without any contact with the cooling water. The cooling water flows in a closed circuit through the condenser and the dry tower heat exchanger.

4.4.2.3 Comparison of Direct and Indirect Dry Cooling Systems--

The direct system has a thermodynamic and operating advantage over the indirect system in that it does not require the use of a condenser and an intermediate loop.

The major disadvantages of the direct system include: 1) the large-bore exhaust steam pipes which transport the steam to the heat exchangers are often difficult to accommondate, 2) the extensive vacuum system is susceptible to air leakages, 3) a large volume of air must be evacuated during startup, and 4) the heat exchangers must be located close to the turbine building in order to limit the pressure drop in the exhaust steam piping.

Traditionally, it has been stated that direct systems would be best suited to units not exceeding 200 MWe; however, the present operation of the 330-MWe Wyodak unit indicates that units over 200 MWe are possible using direct dry cooling.

4.4.2.4 Comparison of Spray Condenser and Surface Condenser--

A spray condenser offers the following principal advantages as compared to a surface condenser:

1. Since the terminal difference is nearly zero, it is possible to achieve a better vacuum with the same warm water outlet temperature.

2. The improved heat transfer performance results in a smaller size and, consequently, lower cost of the condenser and less required headroom under the turbine.

3. The omission of condenser tubes reduces first cost, operational problems (fouling, corrosion), and eliminates the possibility of raw water leaking into the feedwater circuit.

The major disadvantage is the fact that feedwater and the cooling water are mixed in the spray condenser which imposes the need to use feedwater-quality water in the cooling system. Since the cooling water flow may be 30 times as great as the feedwater flow, a large amount of feedwater-quality water is required.

In nuclear application, however, the use of the surface condenser is the best and potentially the only choice because of possible radioactive contamination of the turbine exhaust steam. The use of the surface condenser also permits greater flexibility in the heat rejection circuit, e.g., the wet/dry cooling systems described in Section 5 and the ammonia dry cooling system described in Section 6.

4.4.3 Heat Transfer in Dry Tower

The heat transfer mechanisms which take place over the exterior of the finned-tube heat exhanger of a dry tower involve mainly convection. The overall thermal resistance to heat transfer from water or condensing steam flowing inside the tubes to the air flowing over the outside tube-and-fin surfaces is composed of the following series components:

1. The tube-side (water or steam) film resistance, r_t^f

2. The tube-side fouling resistance to the conduction of heat through fouling deposits on the inside tube wall, r_t^d

3. The conduction resistance of the tube wall, r^m

4. The bond resistance between fin base, and tube, r_s^g

5. The air-side fouling resistance to the conduction of heat through fouling deposits on the outside tube wall, r_s^d

6. The air-side convective film resistance, r_s^f

Thus, the overall thermal resistance R is equal to:

$$R = r_t^f + r_t^d + r^m + r_s^g + r_s^d + r_s^f \qquad (4.33)$$

Of the six individual thermal resistances, the air-side film resistance is the dominant component. The reciprocal of R is called the overall heat transfer coefficient or overall thermal conductance.

Correlations of friction factor and heat transfer coefficients are available in open literature for calculating the corresponding air-side and tube-side film resistances and the air-side and tube-side pressure drops.

On the water-side, the friction factor can be predicted by the classical Blasius equation(50) for flow in circular tubes. The water-side heat transfer coefficient can be calculated by the Dittus-Boelter correlation for turbulent flow(50). The air-side performance parameters are not as well established as their water-side counterparts. A number of correlations are, however, available. The commonly used ones are those developed by Robinson and Briggs(51) and Briggs and Young(52) for air-side pressure drop and heat transfer, respectively.

The metal resistance of the tube wall can be easily calculated. However, the fouling resistances and the bond resistance are not generally available and should be obtained from heat exchanger manufacturers.

Using the overall heat transfer coefficient, there are two standard methods used to calculate the heat transfer from the dry heat exchangers. These two methods are briefly described below:

1) LMTD Method

The total heat transfer to the air is expressed by the following formula:

$$Q = U \cdot (\mathrm{LMTD}) \cdot A \cdot F_g \qquad (4.34)$$

where:

Q = total heat transfer of the exchanger, Btu/hr.

U = overall coefficient of heat transfer, Btu/hr-ft^2-$^\circ$F.

LMTD = logarithmic (natural) mean temperature difference, $^\circ$F.

F_g = dimensionless correction factor for flow arrangement (crossflow usually exists in a dry tower and $F_g = 0.95$ to 1.0) (see Reference 53).

A = surface area on which U is based, ft^2.

The logarithmic mean temperature difference LMTD is the temperature driving force for the transfer of heat between the fluid inside the tubes and the air flowing across the tubes. The LMTD is expressed by the following formula:

$$\text{LMTD} = \frac{\text{GTTD} - \text{LTTD}}{\ln\left[\frac{\text{GTTD}}{\text{LTTD}}\right]} \qquad (4.35)$$

Figure 4.28 illustrates the basic temperature diagram and the definitions of GTTD and LTTD as it applies to an indirect dry cooling tower system with surface condenser.

In evaluating the overall heat transfer coefficient, U, using the correlations discussed in Section 4.4.3, the fin efficiency must be taken into consideration as illustrated in Reference 53. The fin efficiency is defined as the ratio of the heat transferred across the fin surface to the heat which would be transferred if the entire fin surface to the heat which would of the fin base.

Equation (4.34) can be combined with the air energy balance and water energy balance equations to determine the performance or the required size of the heat exchanger for a particular plant heat load requirement. Examples using this procedure to size dry towers are illustrated in Reference 54.

2) The E-Ntu Method

Calculation of heat transfer in dry heat exchangers can also be determined using the so called effectiveness-Ntu method. The method is defined in the following terms: 1) the heat exchanger effectiveness (E), 2) the number of heat transfer units (Ntu), and 3) the ratio of heat capacity rates of the shell- and tube-side fluids (R).

For a given flow arrangement, e.g., crossflow arrangement which is generally used in a dry cooling tower, the effectiveness E is a function of Ntu and R(55,56). Tables in terms of the above mentioned three factors can be found in Reference 56. These terms are further described below:

1) The Heat Exchanger Effectiveness (E)

This is defined as the ratio of the actual rate of heat transfer Q to the maximum rate of heat transfer permitted by the Second Law of Thermodynamics. The equation for the effectiveness of air-water heat exchangers in dry towers under normal operating conditions, where $M_a C_{pa} < M_w C_{pw}$, is:

$$E = \frac{M_w C_{pw} \quad (T_{w,in} - T_{w,out})}{M_a C_{pa} \quad (T_{w,in} - T_{a,in})} = \frac{Q_{rej}}{Q_{max}} \tag{4.36}$$

where:

M_w, M_a = mass flow rate of water and air respectively.

C_{pw}, C_{pa} = specific heat of water and air respectively.

$T_{w,in}$, $T_{w,out}$ = temperature of water in and out of the heat exchanger respectively.

$T_{a,in}$, $T_{a,out}$ = temperature of air in and out of the heat exchanger respectively.

2) The Number of Heat Transfer Units (Ntu)

This term is a measure of the size of the heat exchanger from the point of view of heat transfer and is defined as:

$$Ntu = \frac{UA}{M_a C_{pa}} \tag{4.37}$$

where:

U = overall heat transfer coefficient of the heat exchanger.

A = the heat transfer area on which the overall heat transfer coefficient is based.

3) Heat Capacity Ratio (R)

R is defined as:

$$R = \frac{M_a C_{pa}}{M_w C_{pw}} \tag{4.38}$$

where it is assumed that, under normal operating conditions, $M_a C_{pa} < M_w C_{pw}$.

Both the LMTD and the effectiveness Ntu methods can be used in the design and performance calculation for dry cooling towers. The LMTD method is more convenient to use for the design of heat exchangers to given temperature specifications, i.e., when the inlet and exit temperatures of both fluids are known. The effectiveness Ntu method, on the hand, is preferrable for sizing dry towers using standard heat exchanger modules, i.e., the surface area is known, but the fluid exit temperatures must be determined.

4.4.4 Design of Dry Cooling Towers

The design of the dry tower includes the sizing of fin-tube heat exchanger modules for the plant heat load and air moving equipment to provide the necessary air flow.

In mechanical draft towers, the air moving equipment consists of large diameter axial-flow fans. The finned tubes are assembled into modules with common inlet and outlet headers to form cells. Each cell is served by one or more fans. A sufficient number of cells is sized to satisfy the heat transfer requirement of the power plant. The cells are arranged "in-line" or "back-to-back" to form towers.

In natural draft towers, the tower stack structure above the fin-tube modules induces the air flow across the modules. The tube modules are located at the base of the tower in alternative arrangements. Two arrangements are shown in Figure 4.29.

1. Vertically around the bottom of the tower
2. A-frame bundles with tubes in the horizontal position and placed inside the tower

The mechanical draft tower can also be designed in a cylindrical arrangement with fans on top of the tower. This design is called the circular or round mechanical tower.

4.4.4.1 Sizing of Mechanical Draft Dry Towers--

To size a mechanical draft dry tower used in an indirect dry cooling system using water with commercially available cells to perform a required heat duty, the number of cells needed is determined by the water velocity through the cell tubes, the number of tubes per cell, the number of tube passes and the tube size.

The total tube-side cross-sectional area, A_w, for water flow in a cell is given by:

$$A_w = \frac{\pi D_i^2}{4} \cdot \frac{N_t}{N_p} \tag{4.39}$$

where:

D_i = inside diameter of tube.

N_t = number of tubes in a cell.

N_p = number of tube passes for water flow.

The water flow rate per cell, W_c, is given by:

$$W_c = \rho A_w V_w \tag{4.40}$$

where:

ρ = density of water.

V_w = water velocity.

The number of cells required is given by:

$$N = \frac{W}{W_c} \tag{4.41}$$

where:

W = total mass flow rate of water for the dry tower.

To determine the proper W_c and then the number of cells required, the velocity V_w is varied such that both the water-side and air-side energy balances are matched with the heat transfer equation given by the LMTD method or the Ntu method as discussed in Section 4.4.3.

4.4.4.2 Sizing of Natural Draft Dry Towers--

In sizing a natural draft tower, the heat transfer equation for the tower (Section 4.4.3) must be solved in conjunction with the draft equation for the air flow. The draft balance in a natural draft tower has been treated in Section 4.1.5. A simplified equation developed for the natural draft dry tower by Rozenman and Pundyk(57) is given below:

$$(c)\cdot Y_{eff} = M_{air} \cdot (\alpha) \cdot \frac{2T_1{}^2}{(T_2 - T_1)\ (T_2 + T_1)} \qquad (4.42)$$

where:

c = a constant combining fin-tube module geometry and air physical properties.

Y_{eff} = effective height of the tower.

M_{air} = mass flow rate of air through the tower.

α = a constant related to fin-tube module friction characteristics (1.7 to 1.95).

T_1, T_2 = entering and exit air temperature.

4.4.4.3 Design Parameters--

In designing dry cooling towers with commercially available fin-tube modules, the major design parameters are the cooling range, RA, and the approach temperature, APP, or the initial terminal temperature difference, ITD. This can be seen from the heat transfer equation given by the Ntu method for sizing dry towers with fixed design modules and from the definition of ITD, wherein,

$$Q_{Tower} = (N)_{mod}\ (ITD)\ (MC_p)_{mod}\ (E) \qquad (4.43)$$

$$ITD = APP + RA$$

where:

$(N)_{mod}$ = number of modules.

ITD = initial temperature difference.

$(MC_p)_{mod}$ = heat capacity of the air flow per module.

E = heat exchanger effectiveness.

APP = temperature difference between the cold water temperature and the dry bulb temperature of ambient air.

RA = cooling range of the tower.

For fixed module design, the air mass flow rate and the terms $(MC_p)_{mod}$ and (E) are constant. Thus, the ITD determines the number of modules required for a given heat duty, i.e., the number of modules is inversely proportional to the ITD value selected. The variation of ITD can be achieved by varying the range or approach or both.

4.4.5 High Back Pressure Turbines

The low heat transfer coefficients of the finned surface require large dry cooling surfaces to effect the required heat transfer during high ambient temperatures. One method which can be used to reduce the size of the dry cooling surface (and, consequently, its capital cost) is the use of a steam-turbine capable of operating at turbine back pressures up to 15 in. HgA to increase the temperature potential for heat transfer. The turbine can be either a modification of a conventional turbine or a special design solely intended for dry cooling applications.

Turbine-generator manufacturers have studied the design problems associated with the development of high back pressure turbines specifically for dry cooling. In the United States, both General Electric (GE) and Allis-Chalmers have completed designs of high back pressure turbines for both fossil and nuclear applications. However, only GE is offering a 3600-rpm unit commercially, which is capable of operating at 15 in. HgA in sizes up to 750 MWe for fossil reheat application. As indicated in Reference 48, Allis-Chalmers has postponed the model testing of the last stage of its high back pressure turbine. The Allis-Chalmers designs are shown in Figure 4.30 along with a conventional turbine of approximately the same rating. The difference in size is considerable.

4.4.6 Operating Experience of Dry Cooling Towers

Although dry cooling has been used for industrial cooling for many years, it was only recently that the applications were made to the rejection of heat from steam-electric power plants. Most of the operating experience, however, was obtained in Europe or Russia. As indicated in Table 4.1, the first power plant installation with a dry cooling system having a rated output in excess of 100 MWe was the Rugeley station in England, which began operation in 1961.

The Battelle Pacific Northwest Laboratories(58) conducted a survey of the European dry cooling tower operating experience under the sponsorship of the U. S. Energy Research and Development Administration. The purpose of the study was to provide a basis of confidence that dry cooling is a reliable technology applicable to U. S. operating requirements. The study concluded that dry cooling system represents a mature and reliable technology and can be readily applied in the United States.

In the United States in 1977, the only operational dry cooling systems for power plant applications are the two indirect dry cooling systems serving two small units of 3 and 20 MWe operated by the Black Hill Power and Light Company and one direct dry cooling system at Braintree, Massachusetts (25 MWe) 1977(45). However, one large dry cooling system has been purchased in the United States. This dry cooling system will serve the 330-MWe station built at Wyodak, Wyoming for the Black Hills Power and Pacific Power and Light Companies and began operation in 1978.

4.5 DESIGN AND COST OF CONVENTIONAL COOLING SYSTEMS

4.5.1 General Description

As indicated in Section 3 in order to compare alternate cooling systems on a common economic basis, several penalty costs must be included besides the capital cost. In general as the size of a cooling system alternative becomes larger, its performance improves and the capital cost of the cooling system increases, but the penalty cost decreases. At some point, a minimum exists for the combined cost of capital and penalty, and this minimum represents the best economic trade-off between the two costs. The minimum combined cost system is called an optimum or optimized system. Economic and environmental comparisons of cooling system alternatives are then made utilizing the costs of these optimum systems (see Sections 3 and 11).

One document, Reference 59, contains design, performance, and cost information obtained through an optimization analysis using the fixed source and fixed demand method as discussed in Section 3. These data enable adjustments to be made which reflect different economic conditions from those used in the original design analysis. In the following subsections, the costs are adjusted to 1978 economic conditions. In addition, pertinent design, cost and performance data extracted from this reference are also provided to facilitate adjustments to other economic conditions.

In all the tables presented in this subsection, the names of the cooling system alternatives have been abbreviated as follows:

Abbreviated Name	Cooling System Name
Mech. Wet	Mechanical draft wet tower cooling system
Fan Wet	Fan-assisted natural draft wet tower cooling system
Nat. Wet	Natural draft wet tower cooling system
Pond	Constructed pond cooling system
Spray Canal	Power spray module canal cooling system
Mech. Dry	Mechanical draft dry tower cooling system
Nat. Dry	Natural Draft dry tower cooling system

4.5.2 Typical Designs and Costs of Conventional Cooling Systems

The capital, penalty, and total evaluated costs in 1978 dollars of cooling systems for fossil and nuclear power plants are given in Tables 4.2 and 4.3, respectively. The economic factors for the capital and penalty cost adjustments are given in Table 4.4.

The capital cost includes the direct and indirect cost of the major equipment. The direct cost is the cost for the purchase of the equipment and its installation. The indirect cost represents the charges for engineering, construction management, and contingency; this was taken to be 25 percent of the total direct cost. The major equipment included: 1) the cooling device (wet or dry cooling towers, ponds or spray canals), 2) the circulating water system (pipelines, valves, motors, pumps, and structures), and 3) steam condensers.

The penalty cost includes five components which are common to all the systems. These five components include the costs assessed to account for the generating capability and energy losses associated with the ambient effect on cooling system operation, the generating capability and energy required for operating the fans and pumps, and the maintenance requirements for the cooling system. The penalty costs for making up the generating capability represent costs for generating equipment elsewhere in the utility system. For the costs listed in Tables

4.2 and 4.3 this generation equipment is assumed to be similar base load units, either fossil or nuclear units, as the reference plant. The penalty costs for making up the energy losses represent the capitalized costs which will accrue over the lifetime of the reference plant. The cooling system maintenance cost represents charges to a cooling system for services which include periodic maintenance and replacement of parts, calculated as percentages of direct capital costs of the major equipment.

Although prepared specifically for nominal 1000-MWe power plants, these costs on a dollar per kilowatt basis are approximately correct for stations varying in size from 400 to 1200 MWe. The design conditions and size of the cooling system for 1000-MWe plants are given in Tables 4.5 and 4.6. A brief description of the major equipment is given in Table 4.7.

4.5.3 Adjustment of Capital and Penalty Costs

The costs given in the previous section have been adjusted to 1978 dollars and a particular set of economic factors from the data given in References 41 and 42. These costs, given in dollars per kilowatt and mils per kilowatt-hour, can be used to give quick and rough estimates of the costs of different cooling systems for specific power plants. To obtain more accurate estimates, the capital and penalty cost components should be adjusted from the base values given in Reference 59 to the specific economic and operational factors applicable to that particular plant and should include additional capital or operating cost components, such as the make-up water supply, purchase and treatment costs, blowdown disposal costs, etc.(41, 60). The capital cost elements taken directly from Reference 59 are provided in Tables 4.8, 4.9, and performance data derived from this reference are given in Tables 4.10 and 4.11.

TABLE 4.1. POWER PLANTS OVER 100 MWe USING DRY COOLING SYSTEM(46,48)

Dry Cooling System Type	Power Station	Rating MWe	Heat Rejection 10^6 Btu/hr	Maker	Commission Date
INDIRECT	Gyongyos 1 (Hungary)	100	425	Hoterv	1969
		100	425	Hoterv	1970
	Rugeley (England)	120	575	EE/Heller	1962
	Ibbenburen (West Germany)	150	645	GEA/Transelektro	1967
	Gyongyos 2 (Hungary)	220	905	Hoterv	1971
		220	905	Hoterv	1972
	Razdan (USSR)	220	956	Transelektro	1970
		220	956	Transelektro	1971
		220	956	Transelektro	1972
		220	956	Transelektro	1974
		220	956	Transelektro	1975
		220	956	Transelektro	1976
	Grootvlei V (South Africa)	200	1139	M.A.N./GKN	1971
	Schmehausen (West Germany)	360	1500	GEA/BO	1976
DIRECT	USTA Utrillas (Spain)	160	667	GEA	1970
	Wyodak (USA)	330	1694	GEA	1978

TABLE 4.2. COSTS OF TYPICAL CONVENTIONAL COOLING SYSTEMS FOR FOSSIL POWER PLANTS (1978 DOLLARS)*

Cooling System	Capital Cost, $/kW	Penalty Cost, $/kW	Total Evaluated Cost	
			$/kW	Mills/kWH
Once-through	15.16	6.36	21.52	0.60
Mech. Wet	21.57	27.72	49.29	1.35
Nat. Wet	26.96	21.02	47.98	1.31
Fan Wet	27.77	22.73	50.50	1.38
Pond	38.50	32.74	71.24	1.95
Spray Canal	23.99	25.63	49.62	1.36
Mech. Dry	34.29	125.04	159.33	4.37
Nat. Dry	37.87	115.98	153.85	4.22

*See page 78 for full name of cooling system which is abbreviated in this table.

TABLE 4.3. COSTS OF TYPICAL CONVENTIONAL COOLING SYSTEMS FOR NUCLEAR POWER PLANTS (1978 DOLLARS)*

Cooling System	Capital Cost, $/kW	Penalty Cost, $/kW	Total Evaluated Cost	
			$/kW	Mills/kWH
Once-through	21.03	5.90	26.93	0.74
Mech. Wet	27.53	29.18	56.71	1.55
Nat. Wet	29.83	29.25	59.08	1.62
Fan Wet	32.36	25.50	57.86	1.58
Pond	50.72	32.10	82.82	2.27
Spray Canal	25.45	35.10	60.55	1.66
Mech. Dry	46.89	164.64	211.53	5.80
Nat. Dry	57.34	141.84	199.18	5.46

*See page 78 for full name of cooling system which is abbreviated in this table.

TABLE 4.4. ECONOMIC FACTORS

Cost Year	1978
Plant Capacity Factor	75%
Annual Fixed Charge Rate	18%
Plant Life	40 years
Capacity Penalty Charge Rate* (For capacity loss at the peak ambient temperature and auxiliary power)	$563/kW (nuclear) $450/kW (fossil)
Energy Cost*	10 mills/kWh (nuclear) 15 mills/kWh (fossil)
Escalation rate for material and labor costs	7% per year
Cooling System Maintenance Charge	0.5% of direct capital cost

*These values were adjusted for 1978 from information given in References(40,41).

TABLE 4.5. DESIGN CONDITION AND SIZE OF TYPICAL CONVENTIONAL COOLING SYSTEMS FOR A 1000-MWe FOSSIL POWER PLANT(59)

Base Plant Condition: Gross Output = 1043 MWe, Heat Rate = 7365 Btu/kWh, Exhaust Pressure = 1.5 in.HgA

Design Ambient Condition: Dry Bulb Temperature = 93°F, Wet Bulb Temperature = 74°F, Wind Speed = 5 mph

Variable Name	Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
General								
Design Cold Water Temperature, °F	57.0	90.0	84.0	90.0	103.0	94.0	131.0	131.0
Design Approach, °F	-	16.0	10.0	16.0	29.0	20.0	38.0	38.0
Design Range, °F	15.0	21.0	24.0	24.0	16.0	17.0	25.0	28.0
Plant Capacity at Cooling System Design Point, MWe	1043	1020	1026	1014	1000	1020	938	932
Design Turbine Back Pressure, In.HgA	1.50	3.17	2.91	3.45	3.95	3.16	10.12	10.86
Maximum Turbine Back Pressure, In.HgA	2.14	3.22	2.98	3.66	4.00	3.17	11.89	12.80
Design Heat Load, 10^9 Btu/hr	4.12	4.20	4.18	4.22	4.27	4.20	4.48	4.50
Condenser								
Surface Area, 10^3 sq ft	396	627	595	590	715	688	608	576
Number of Tubes, 10^3	37.0	53.8	46.9	47.3	71.8	66.5	48.2	43.3
Tube Length, ft	41.0	44.5	48.4	47.7	38.1	39.5	48.1	50.9

(continued)

TABLE 4.5 (continued)

Variable Name	Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
Cooling Water Pump								
Circulating Water Flow Rate, 10^3 gpm	549	400	348	352	533	494	358	321
Number of Pumps	4	3	2	2	3	3	2	2
Pumping Head, ft. of Water	23.7	78.1	79.2	91.6	33.3	33.2	44.2	63.8
Pumping Power Requirement, bph/pump	924	2952	3915	4570	1679	1555	2245	2908
Rated Pump Motor Size, hp/pump motor	1250	3500	4500	5000	2000	2000	2500	3500
Terminal Heat Sink								
Total Power Requirement, 10^3 bhp	-	4.28	5.24	-	-	8.55	17.77	-
Terminal Heat Sink Size:	-	-	-	-	-	-	-	-
Number of Cells	-	23	-	-	-	-	94	-
Tower: Number of Towers	-	-	2	1	-	-	-	1
Base Diameter, ft	-	-	226	385	-	-	-	443
Tower Height, ft	-	-	250	500	-	-	-	446
Fan: Number of Fans/Tower	-	-	20	-	-	-	-	-
Fan Diameter, ft	-	28	28	-	-	-	28	-
Canal: Number of Modules	-	-	-	-	-	114	-	-
Canal Width, ft	-	-	-	-	-	256	-	-
Canal Length, ft	-	-	-	-	-	3340	-	-
Pond Area, Acres	-	-	-	-	432	-	-	-

TABLE 4.6. DESIGN CONDITION AND SIZE OF TYPICAL CONVENTIONAL COOLING SYSTEMS FOR A 1000-MWe LWR POWER PLANT(59)

Base Plant Condition: Gross Output = 1096 MWe, Heat Rate = 9760 Btu/kWh, Exhaust Pressure = 1.5 in.HgA

Design Ambient Condition: Dry Bulb Temperature = 93°F, Wet Bulb Temperature = 74°F, Wind Speed = 5 mph

Variable Name	Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
General								
Design Cold Water Temperature, °F	57.0	91.0	87.0	92.0	108.0	100.0	135.0	129.0
Design Approach	-	17.0	13.0	18.0	34.0	26.0	42.0	36.0
Design Range, °F	15.0	27.0	29.0	29.0	17.0	26.0	29.0	32.0
Plant Capacity at Cooling System Design Point, MWe	1096	1075	1078	1069	1059	1056	933	940
Design Turbine Back Pressure, In.HgA	1.50	3.85	3.64	4.17	4.65	4.77	12.20	11.38
Maximum Turbine Back Pressure, In.HgA	2.13	3.90	3.71	4.39	4.69	4.78	14.29	13.32
Design Heat Load, 10^9 Btu/hr	6.96	7.03	7.02	7.05	7.09	7.10	7.52	7.49
Condenser								
Surface Area, 10^3 sq ft	670	925	898	892	1157	944	944	893
Number of Tubes, 10^3	62.4	70.1	65.2	65.5	112.0	73.5	69.8	63.0
Tube Length, ft	41.0	50.4	52.6	52.0	39.4	49.1	51.7	54.1

(continued)

TABLE 4.6 (continued)

Variable Name	Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
Cooling Water Pump								
Circulating Water Flow Rate, 10^3 gpm	928	521	484	486	834	546	518	468
Number of Pumps	7	3	3	3	5	4	3	3
Pumping Head, ft of Water	22.2	79.0	75.6	90.3	33.7	36.7	42.4	51.0
Pumping Power Requirement, bph/pump	835	3892	3462	4153	1594	1422	2077	2259
Rated Pump Motor Size, hp/pump Motor	1000	4500	4000	4500	2000	1750	2500	3000
Terminal Heat Sink								
Total Power Requirement, 10^3 bhp	-	6.07	6.66	-	-	8.55	26.40	-
Terminal Heat Sink Size:	-	-	-	-	-	-	-	-
Number of Cells	-	33	-	-	-	-	141	-
Tower: Number of Towers	-	-	2	1	-	-	-	2
Base Diameter, ft	-	-	257	407	-	-	-	397
Tower Height, ft	-	-	250	527	-	-	-	416
Fan: Number of Fans/Tower	-	-	24	-	-	-	-	-
Fan Diameter, ft	-	28	28	-	-	-	28	-
Canal: Number of Modules	-	-	-	-	-	114	-	-
Canal Width, ft	-	-	-	-	-	256	-	-
Canal Length, ft	-	-	-	-	-	3340	-	-
Pond Area, Acres	-	-	-	-	565	-	-	-

TABLE 4.7. LIST OF MAJOR EQUIPMENT(59)

Item	Description
Condensers	Each cooling system has three field-tubed main surface condensers with fabricated steel water boxes and steel shell. Each condenser has 1-inch o.d., 20 BWG gauge, 304 stainless steel tubes and a design water velocity of 7.0 ft/sec. The condenser has one tube pass for the once-through cooling system and two tube passes for the closed cooling systems.
Circulating Water Pumps and Motors	The circulating water pumps are each of the vertical, wet pit, motor-driven type with 4160 volts, 3-phase, 60-hertz motors. The pumps have carbon steel casings with chrome steel shaft and bronze impeller.
Terminal Heat Sink	The following are the description of alternative cooling devices.
A) Mechanical Draft Rectangular Wet Cooling Tower	The mechanical draft wet tower cells or modules are the induced draft, cross-flow type of concrete construction with 41 feet fill height. Each cell has a fan; the fan has a diameter of 28 feet and is driven by a 200-horsepower motor. The cell dimensions are 71 feet wide, 36 feet

(continued)

TABLE 4.7 (continued)

Item	Description
Terminal Heat Sink (Cont'd)	long, and 54 feet high.
B) Natural Draft Wet Cooling Tower	The natural draft wet towers are the counterflow type with a maximum base diameter of 500 feet. The hyperbolic shell is made of reinforced concrete with a minimum thickness of six inches.
C) Fan-assisted Natural Draft Wet Tower	The fan-assisted natural draft towers are the counterflow type with a minimum height of 250 feet. The hyperbolic shell is made of reinforced concrete with a minimum thickness of six inches. The maximum number of fans is 24, with a fan diameter of 28 feet. The fans are driven by 150-horsepower motors.
D) Power Spray Modules	Each spray module has four nozzles mounted on a 120-foot length, 10-inch diameter carbon steel pipe. Each is complete with floats and a pump at the center of the pipe.

(continued)

TABLE 4.7 (continued)

Item	Description
Terminal Heat Sink (Cont'd)	The pump can deliver 10,000 gpm and is driven by a 75-horsepower motor.
E) Mechanical Draft Dry Tower	The mechanical draft dry tower cells are the induced flow type. The cells are arranged back-to-back to form towers. Each cell has 776 tubes arranged in two passes and is equipped with a 150-horsepower motor and 28-foot diameter fan. The cell dimensions are 41 feet wide, 61 feet long and 65 feet high. The tubes are of 1-inch outside diameter admiralty tubes with aluminum fins.
F) Natural Draft Dry Tower	The natural draft tower has a hyperbolic concrete shell with a maximum base diameter of 500 feet and a minimum thickness of six inches. The finned-tube heat exchanger modules are arranged vertically around the tower base. Each module has 176 tubes in two passes. The tubes are of 1-inch outside diameter admiralty tubes with aluminum fins.

TABLE 4.8. CAPITAL COST ELEMENTS OF TYPICAL CONVENTIONAL COOLING SYSTEMS FOR A 1000-MWe FOSSIL PLANT ($$10^6$, 1973 DOLLARS)(59)

Equipment * Item		Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
Circulating Water Structure	(M	0.582	0.424	0.411	0.409	0.414	0.445	0.330	0.320
	(L	1.964	0.286	0.283	0.281	0.272	0.301	0.220	0.210
	(T	2.546	0.710	0.694	0.690	0.686	0.746	0.550	0.530
Circulating Water Pumps & Motors	(E	0.920	0.957	0.793	0.829	0.895	0.914	0.623	0.692
	(M	0.010	0.010	0.009	0.009	0.010	0.010	0.007	0.008
	(L	0.080	0.063	0.042	0.042	0.061	0.062	0.040	0.040
	(T	1.010	1.030	0.844	0.880	0.966	0.986	0.670	0.740
Concrete Pipe	(M	0.640	0.540	0.540	0.539	0.824	0.829	0.800	0.480
	(L	0.699	0.560	0.622	0.621	0.864	0.869	1.120	0.560
	(T	1.339	1.100	1.162	1.160	1.688	1.698	1.920	1.040
Terminal Heat Sink Basins and Foundations	(M	-	0.470	0.280	0.270	-	-	0.180	0.280
	(L	-	0.710	1.120	1.060	-	-	0.370	0.900
	(T	-	1.180	1.400	1.330	-	-	0.550	1.180
Terminal Heat Sink	(E	-	1.891	4.128	5.346	-	2.257	9.821	8.278
	(M	-	0.019	0.042	0.054	0.650	0.023	0.049	0.042
	(L	-	1.030	2.780	1.350	12.950	1.880	1.010	5.750
	(T	-	2.940	6.950	6.750	13.600	4.160	10.880	14.070

(continued)

TABLE 4.8 (continued)

Equipment Item		Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
Condensers, Installed	(E	2.358	3.333	3.143	3.134	3.840	3.681	3.203	3.043
	(M	0.012	0.017	0.016	0.016	0.020	0.019	0.017	0.017
	(L	1.340	1.600	1.550	1.540	1.740	1.700	1.560	1.520
	(T	3.710	4.950	4.709	4.690	5.600	5.400	4.780	4.580
Electrical Work	(E	0.124	0.283	0.233	0.157	0.135	0.392	0.322	0.146
	(M	0.067	0.213	0.175	0.130	0.073	0.295	0.242	0.079
	(L	0.139	0.429	0.352	0.253	0.152	0.593	0.486	0.165
	(T	0.330	0.925	0.760	0.540	0.360	1.280	1.050	0.390
Sub-Total for the Complete Cooling System	(E	3.402	6.464	8.297	9.466	4.870	7.244	13.969	12.159
	(M	1.311	1.693	1.473	1.427	1.991	1.621	1.625	1.226
	(L	4.222	4.678	6.749	5.147	16.039	5.405	4.806	9.145
	(T	8.935	12.835	16.519	16.040	22.900	14.270	20.400	22.530
Indirect Charges		2.334	3.209	4.130	4.010	5.725	3.568	5.100	5.633
Total Capital Investment		11.269	16.044	20.649	20.050	28.625	17.838	25.500	28.163

*

L	Labor
E	Equipment (pump, cooling tower, etc.)
M	Material (pipe, cable, etc.)
T	Total (L+M+E)

TABLE 4.9. CAPITAL COST ELEMENTS OF TYPICAL CONVENTIONAL COOLING SYSTEMS FOR A 1000-MWe LWR POWER PLANT ($$10^6$, 1973 DOLLARS)(59)

Equipment * Item		Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
Circulating Water Structure	(M	0.833	0.504	0.514	0.514	0.509	0.496	0.380	0.360
	(L	2.811	0.344	0.344	0.334	0.339	0.340	0.250	0.240
	(T	3.644	0.848	0.848	0.848	0.848	0.836	0.630	0.600
Circulating Water Pumps & Motors	(E	1.553	1.201	1.150	1.201	1.490	1.040	0.930	0.979
	(M	0.017	0.014	0.014	0.014	0.016	0.012	0.010	0.011
	(L	0.140	0.063	0.064	0.063	0.102	0.084	0.060	0.060
	(T	1.710	1.278	1.228	1.278	1.608	1.136	1.000	1.050
Concrete Pipes	(M	1.040	0.798	0.658	0.338	1.246	0.924	1.190	0.640
	(L	0.999	0.716	0.596	0.316	1.508	0.924	1.270	0.580
	(T	2.039	1.514	1.254	0.654	2.754	1.848	2.460	1.220
Terminal Heat Sink Basins and Foundations	(M	-	0.670	0.320	0.280	-	-	0.270	0.380
	(L	-	1.010	1.280	1.130	-	-	0.560	1.230
	(T	-	1.680	1.600	1.410	-	-	0.830	1.610
Terminal Heat Sink	(E	-	2.713	4.782	5.930	-	2.257	14.726	14.557
	(M	-	0.027	0.048	0.060	0.850	0.023	0.074	0.073
	(L	-	1.470	3.220	1.500	16.950	1.880	1.520	10.030
	(T	-	4.210	8.050	7.490	17.800	4.160	16.320	24.660

(continued)

TABLE 4,9 (continued)

Equipment Item		Once-Through	Mech. Wet	Fan Wet	Nat. Wet	Pond	Spray Canal	Mech. Dry	Nat. Dry
Condensers, Installed	(E	3.572	4.517	4.368	4.348	5.803	4.617	4.577	4.328
	(M	0.018	0.023	0.022	0.022	0.027	0.023	0.023	0.022
	(L	1.670	1.910	1.870	1.860	2.270	1.940	1.920	1.850
	(T	5.260	6.450	6.260	6.230	8.100	6.580	6.520	6.200
Electrical Work	(E	0.184	0.375	0.303	0.214	0.225	0.413	0.476	0.191
	(M	0.099	0.282	0.228	0.176	0.122	0.311	0.358	0.104
	(L	0.207	0.568	0.459	0.345	0.253	0.626	0.721	0.215
	(T	0.490	1.225	0.990	0.735	0.600	1.350	1.555	0.510
Sub-Total for the Complete Cooling System	(E	5.309	8.806	10.603	11.693	7.518	8.327	20.709	20.055
	(M	2.007	2.318	1.804	1.404	2.770	1.789	2.305	1.590
	(L	5.827	6.081	7.823	5.548	21.422	5.794	6.301	14.205
	(T	13.143	17.205	20.230	18.645	31.710	15.910	29.315	35.850
Indirect Charges		3.285	4.301	5.058	4.661	7.928	3.978	7.329	8.963
Total Capital Investment		16.425	21.506	25.288	23.306	39.638	19.888	36.644	44.813

*

L	Labor
E	Equipment (pump, cooling tower, etc.)
M	Material (pipe, cable, etc.)
T	Total (L+M+E)

TABLE 4.10. PLANT PERFORMANCE DATA OF A 1000-MWe FOSSIL PLANT USING CONVENTIONAL COOLING SYSTEMS(59)

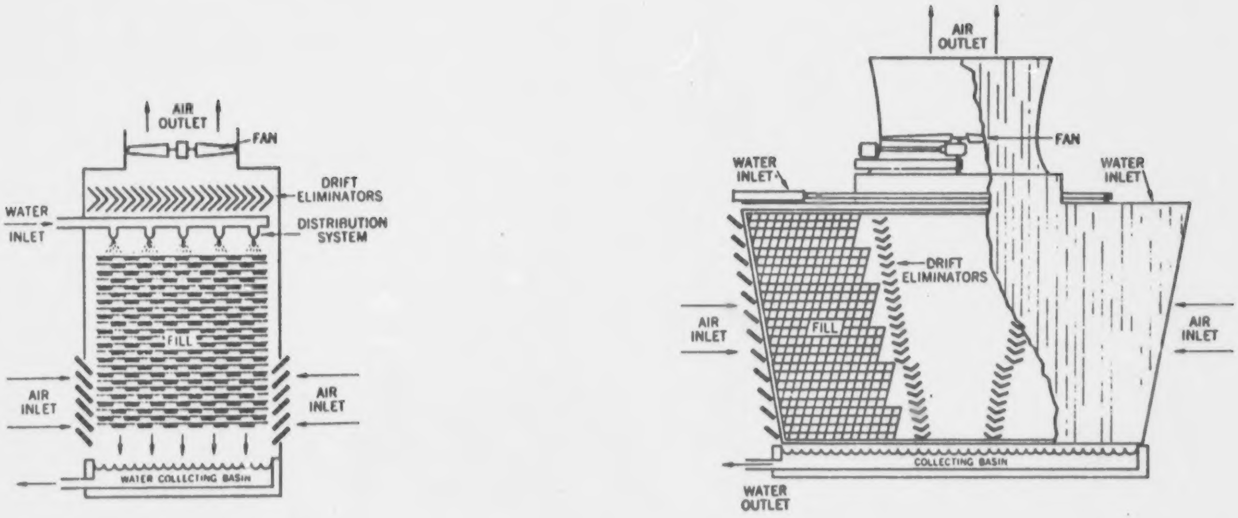
SITE: MIDDLETOWN, U.S.A. (BOSTON, MA. METEOROLOGY)

Cooling System	Capacity Loss at the Highest Ambient Temp., kW	Annual Energy Loss $\times 10^{-7}$ kWH	Capacity (kW) Required by		Annual Energy ($\times 10^{-7}$ kWH) Required by	
			Pumps	Fans	Pumps	Fans
Once-through	5,440	0.19	3,063	0	2.68	0
Mech. Wet	23,500	5.79	7,341	3,485	6.43	3.05
Nat. Wet	34,050	4.42	7,576	0	6.64	0
Fan Wet	18,560	2.68	6,490	3,909	5.69	3.42
Pond	44,240	9.67	4,174	0	3.66	0
Spray Canal	22,380	4.64	3,867	6,378	3.39	5.59
Mech. Dry	118,560	66.64	3,722	13,256	3.26	11.32
Nat. Dry	125,750	67.18	4,821	0	4.22	0

TABLE 4.11. PLANT PERFORMANCE DATA OF A 1000-MWe NUCLEAR PLANT USING CONVENTIONAL COOLING SYSTEMS(59)

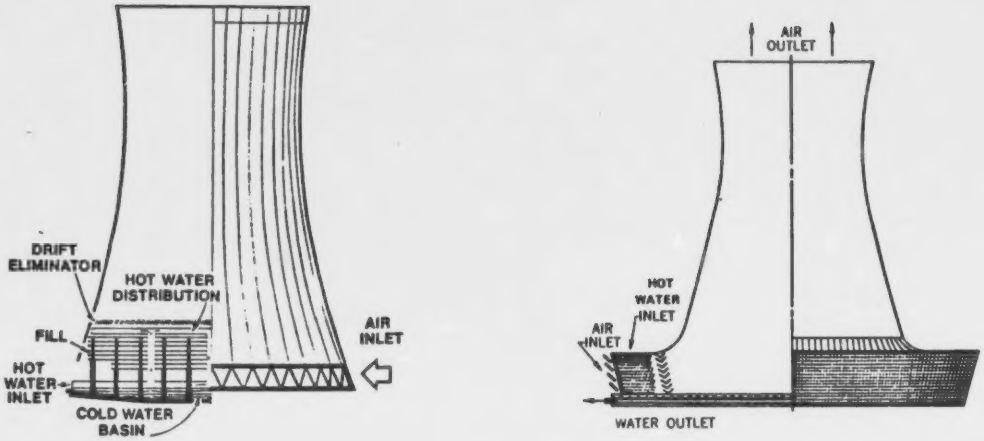
SITE: MIDDLETOWN, U.S.A. (BOSTON, MA. METEOROLOGY)

Cooling System	Capacity Loss at the Highest Ambient Temp., kW	Annual Energy Loss x 10^{-7} kWH	Capacity (kW) Required by		Annual Energy (x 10^{-7} kWH) Required by	
			Pumps	Fans	Pumps	Fans
Once-through	1,590	- 0.047	4,844	0	4.24	0
Mech. Wet	22,460	6.02	9,677	4,921	8.48	4.31
Nat. Wet	31,290	5.18	10,327	0	9.05	0
Fan Wet	19,300	3.69	8,608	4,968	7.54	4.35
Pond	38,370	9.74	6,606	0	5.79	0
Spray Canal	40,830	5.79	4,714	6,378	4.13	5.59
Mech. Dry	180,210	93.53	5,164	19,694	4.52	16.88
Nat. Dry	172,300	92.09	5,618	0	4.92	0


AIR OUTLET
FAN
DRIFT ELIMINATORS
WATER INLET
DISTRIBUTION SYSTEM
FILL
AIR INLET
AIR INLET
WATER COLLECTING BASIN
AIR OUTLET
FAN
WATER INLET
WATER INLET
DRIFT ELIMINATORS
AIR INLET
FILL
AIR INLET
COLLECTING BASIN
WATER OUTLET

(a) Counterflow Tower (b) Crossflow Tower

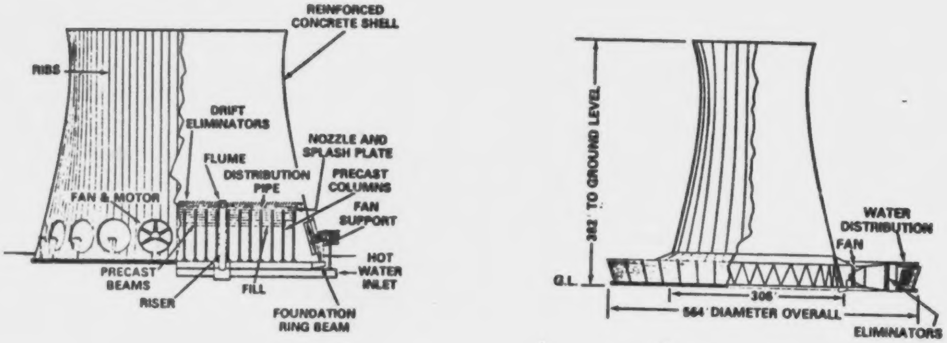
Figure 4.1. Typical mechanical draft wet cooling towers(1). Reprinted from Cooling Tower Fundamentals and Application Principles, 1969, with permission of The Marley Company.


DRIFT ELIMINATOR
HOT WATER DISTRIBUTION
FILL
HOT WATER INLET
COLD WATER BASIN
AIR INLET
AIR OUTLET
HOT WATER INLET
AIR INLET
WATER OUTLET

(a) Counterflow Tower

(b) Crossflow Tower

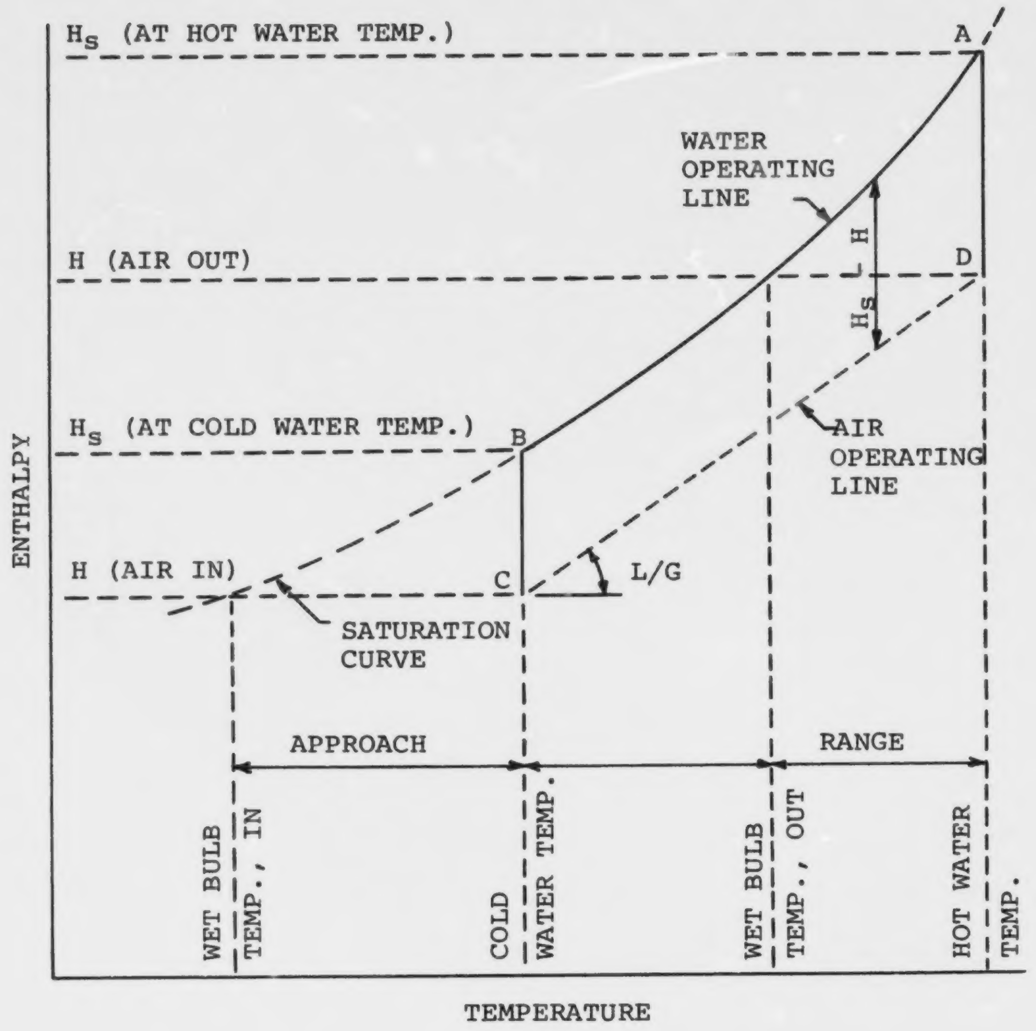
Figure 4.2. Typical natural draft wet cooling towers(1). Reprinted from Cooling Tower Fundamentals and Application Principles, 1969, with permission of The Marley Company.


REINFORCED CONCRETE SHELL
RIBS
DRIFT ELIMINATORS
NOZZLE AND SPLASH PLATE
FLUME
DISTRIBUTION PIPE
PRECAST COLUMNS
FAN & MOTOR
FAN SUPPORT
HOT WATER INLET
PRECAST BEAMS
RISER
FILL
FOUNDATION RING BEAM
382' TO GROUND LEVEL
WATER DISTRIBUTION
FAN
G.L.
306'
564' DIAMETER OVERALL
ELIMINATORS

(a) Counterflow Forced Draft Tower

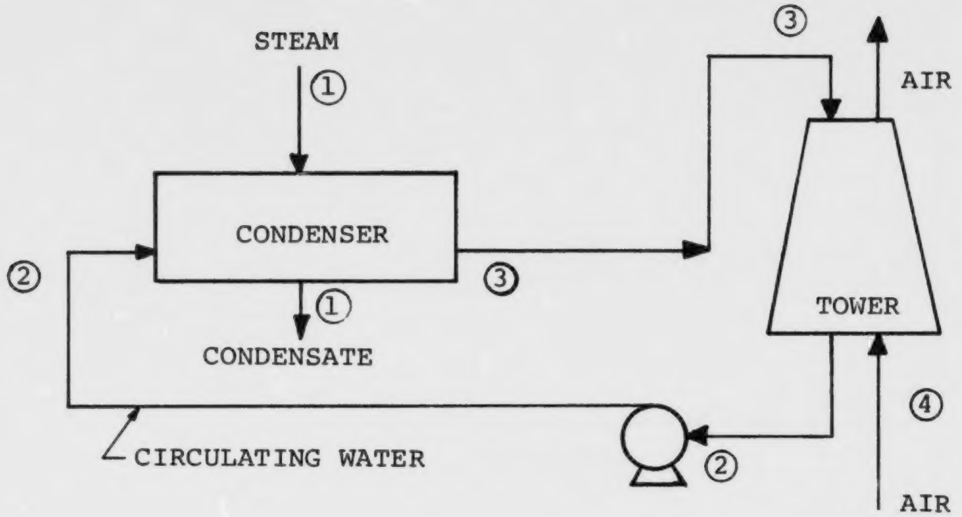
(b) Crossflow Induced Draft Tower

Figure 4.3. Typical fan-assisted natural draft wet cooling towers(4).


H_s (AT HOT WATER TEMP.)
A
WATER OPERATING LINE
H (AIR OUT)
D
$H_s - H$
H_s (AT COLD WATER TEMP.)
B
AIR OPERATING LINE
ENTHALPY
H (AIR IN)
C
L/G
SATURATION CURVE
APPROACH
RANGE
WET BULB TEMP., IN
COLD WATER TEMP.
WET BULB TEMP., OUT
HOT WATER TEMP.
TEMPERATURE

Legend: T_{wb} = wet bulb temperature, °C.
T_{cw} = cold water temperature, °C.
T_{hw} = hot water temperature, °C.
H = enthalpy of moist air, J/Kg of dry air.
H_s = enthalpy of saturated air, J/Kg of dry air.
L/G = liquid/gas mass flow rate ratio, dimensionless.

Figure 4.4. Representation of the wet bulb temperature, range, approach, operating line, and driving force on an enthalpy-temperature diagram for a fresh water tower(8).


STEAM
①
CONDENSER
②
①
CONDENSATE
③
③
AIR
TOWER
④
CIRCULATING WATER
②
AIR

	Evaporative Cooling	Dry Cooling
Range	$T_3 - T_2$	$T_3 - T_2$
Approach	$T_2 - T_4$ (wet bulb)	$T_2 - T_4$ (dry bulb)
Initial Temperature Difference	-------	$T_3 - T_4$ (dry bulb)
Terminal Temperature Difference	T_1 (Sat.) - T_3	T_1 (Sat.) - T_3

Figure 4.5. Cooling Tower Nomenclature.

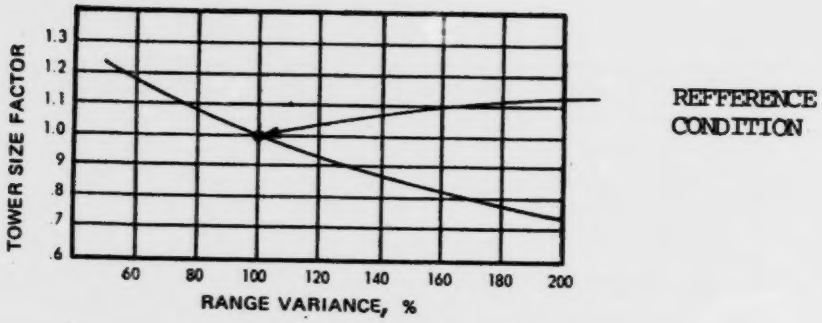


Figure 4.6a. Effect of varying range on tower size(1).

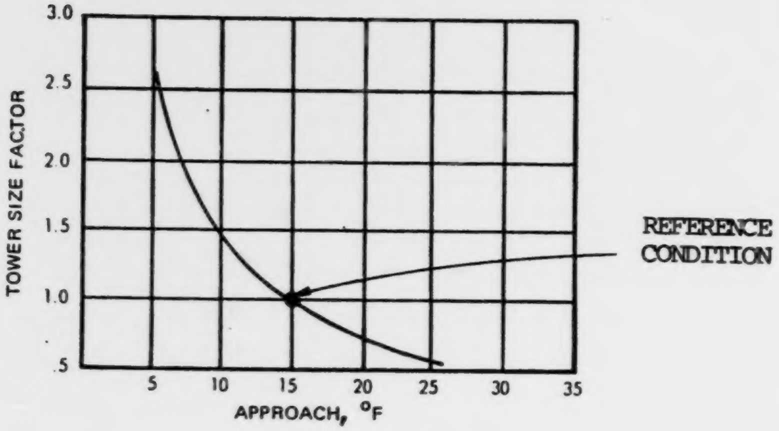


Figure 4.6b. Effect of varying approach on tower size(1).

Figures 4.6a and 4.6b are reprinted from Cooling Tower Fundamentals and Application Principles, 1969, with permission of The Marley Company.

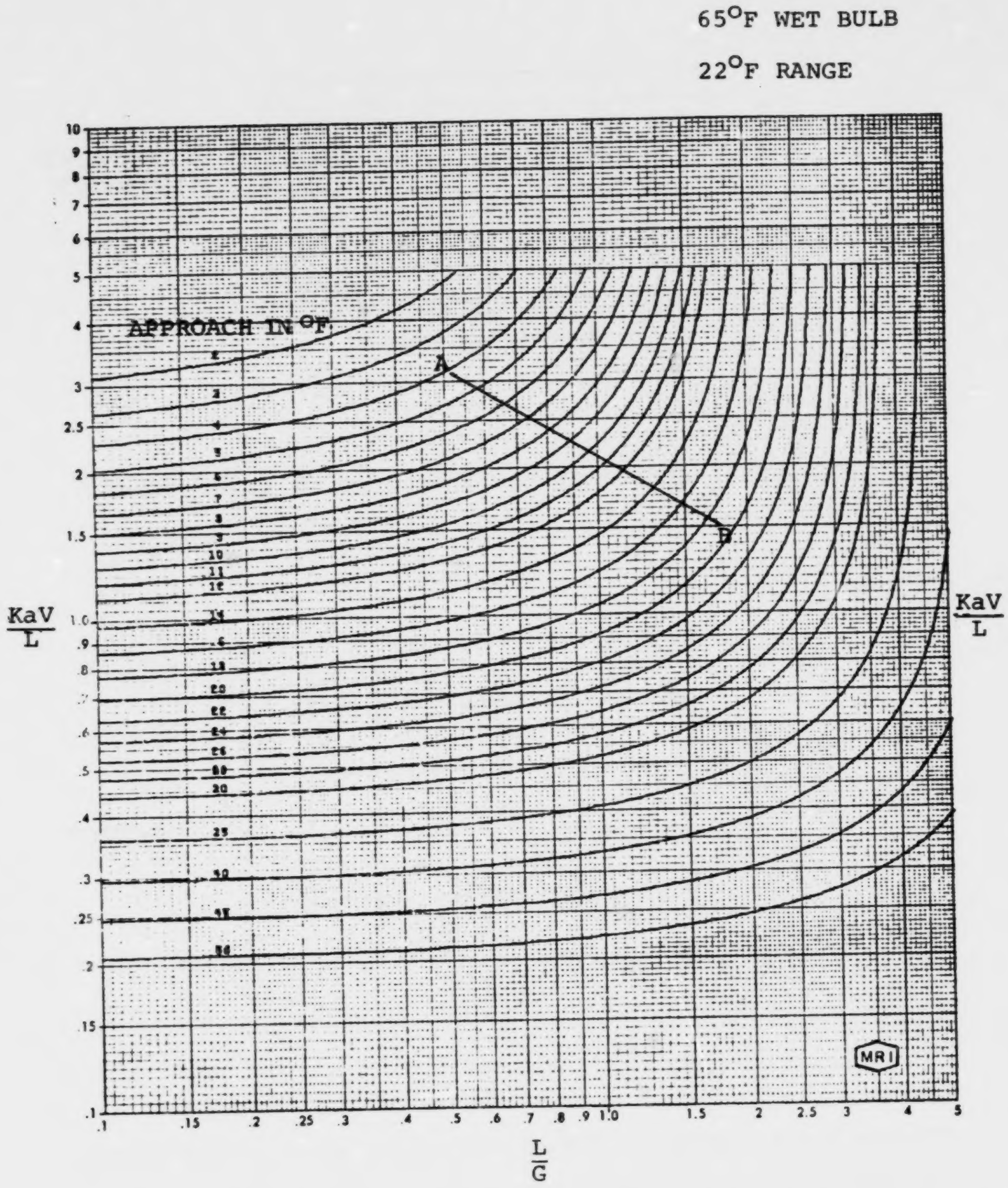


Figure 4.7. Typical performance curves of a wet cooling tower(9).

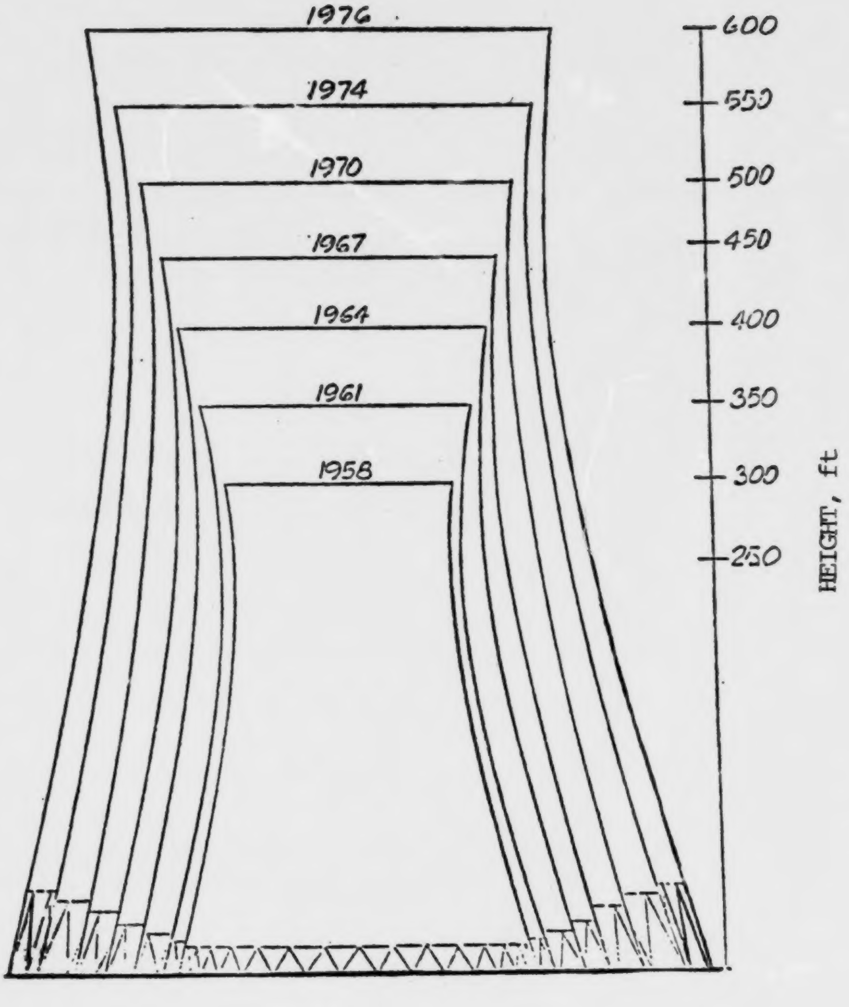

1976
1974
1970
1967
1964
1961
1958
600
550
500
450
400
350
300
250
HEIGHT, ft

Figure 4.8. Trend in tower size for natural draft wet cooling towers.

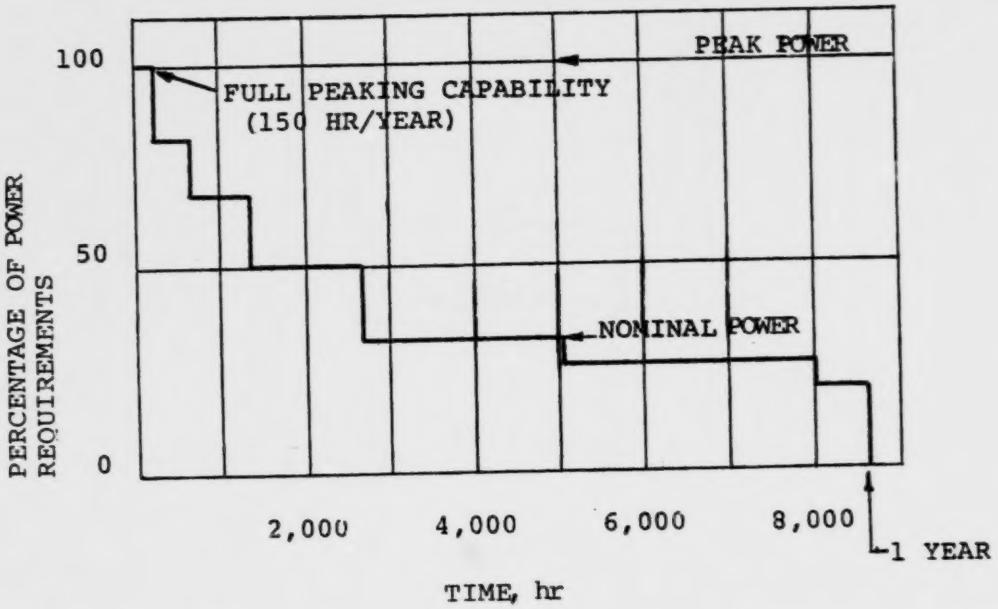


Figure 4.9. Fan power requirements for fan-assisted natural draft cooling tower(2).

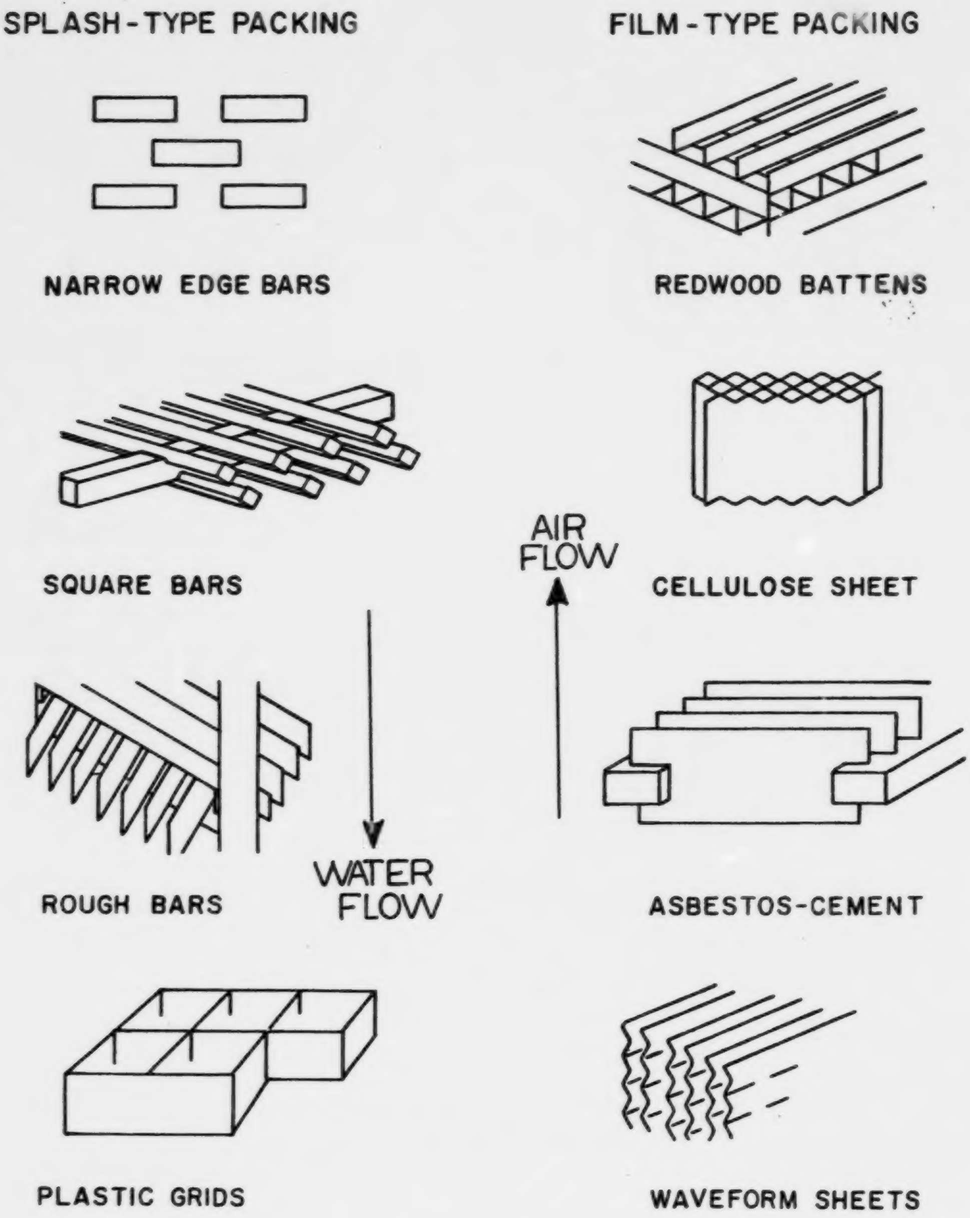

SPLASH-TYPE PACKING
FILM-TYPE PACKING
NARROW EDGE BARS
REDWOOD BATTENS
SQUARE BARS
AIR FLOW
CELLULOSE SHEET
ROUGH BARS
WATER FLOW
ASBESTOS-CEMENT
PLASTIC GRIDS
WAVEFORM SHEETS

Figure 4.10. Typical packing configurations for wet cooling towers(16).

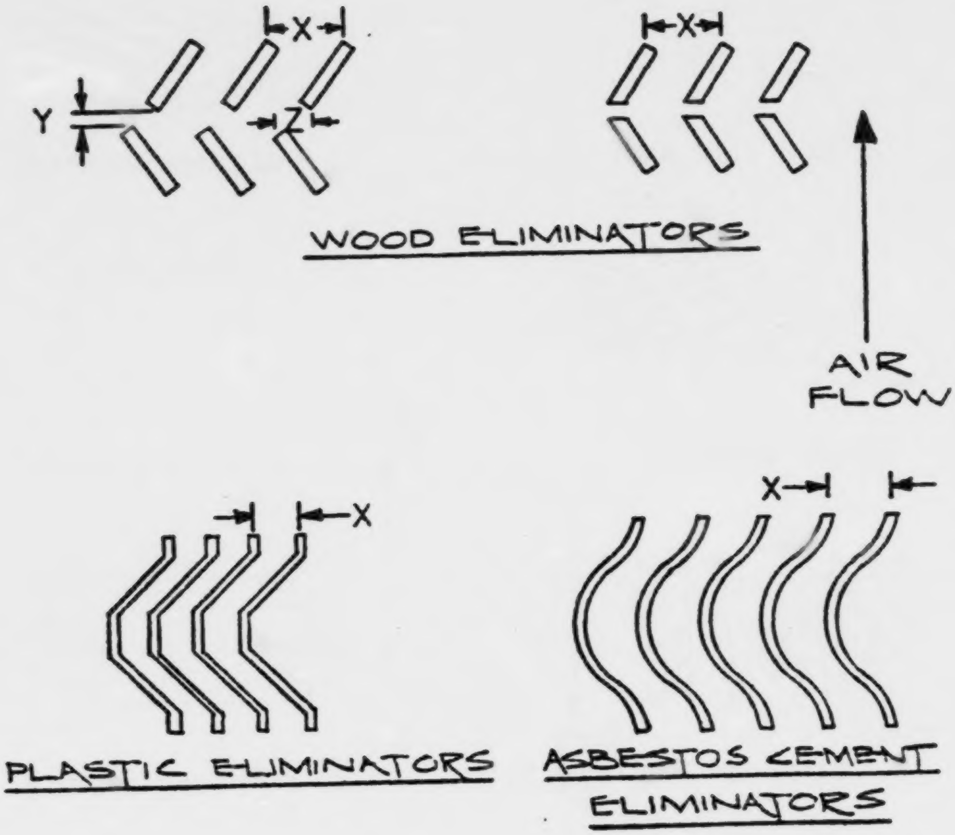

X
Y
Z
X
WOOD ELIMINATORS
AIR FLOW
X
X
PLASTIC ELIMINATORS
ASBESTOS CEMENT ELIMINATORS

Figure 4.11. Typical drift eliminators for wet cooling towers(16).

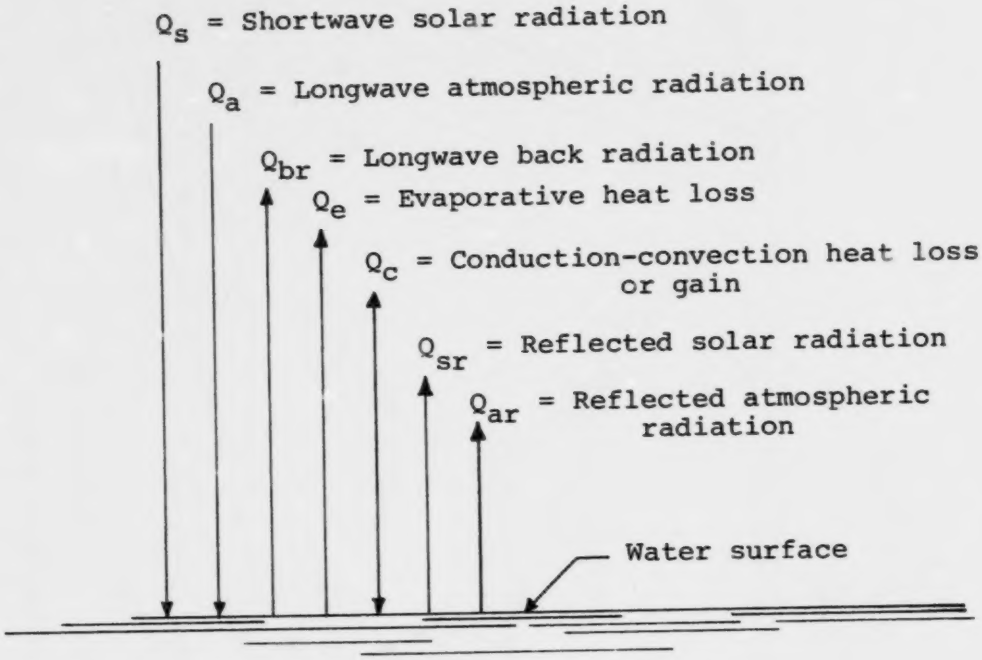

Q_s = Shortwave solar radiation
Q_a = Longwave atmospheric radiation
Q_{br} = Longwave back radiation
Q_e = Evaporative heat loss
Q_c = Conduction-convection heat loss or gain
Q_{sr} = Reflected solar radiation
Q_{ar} = Reflected atmospheric radiation
Water surface

Figure 4.12. Mechanisms of heat transfer across a water surface(22).

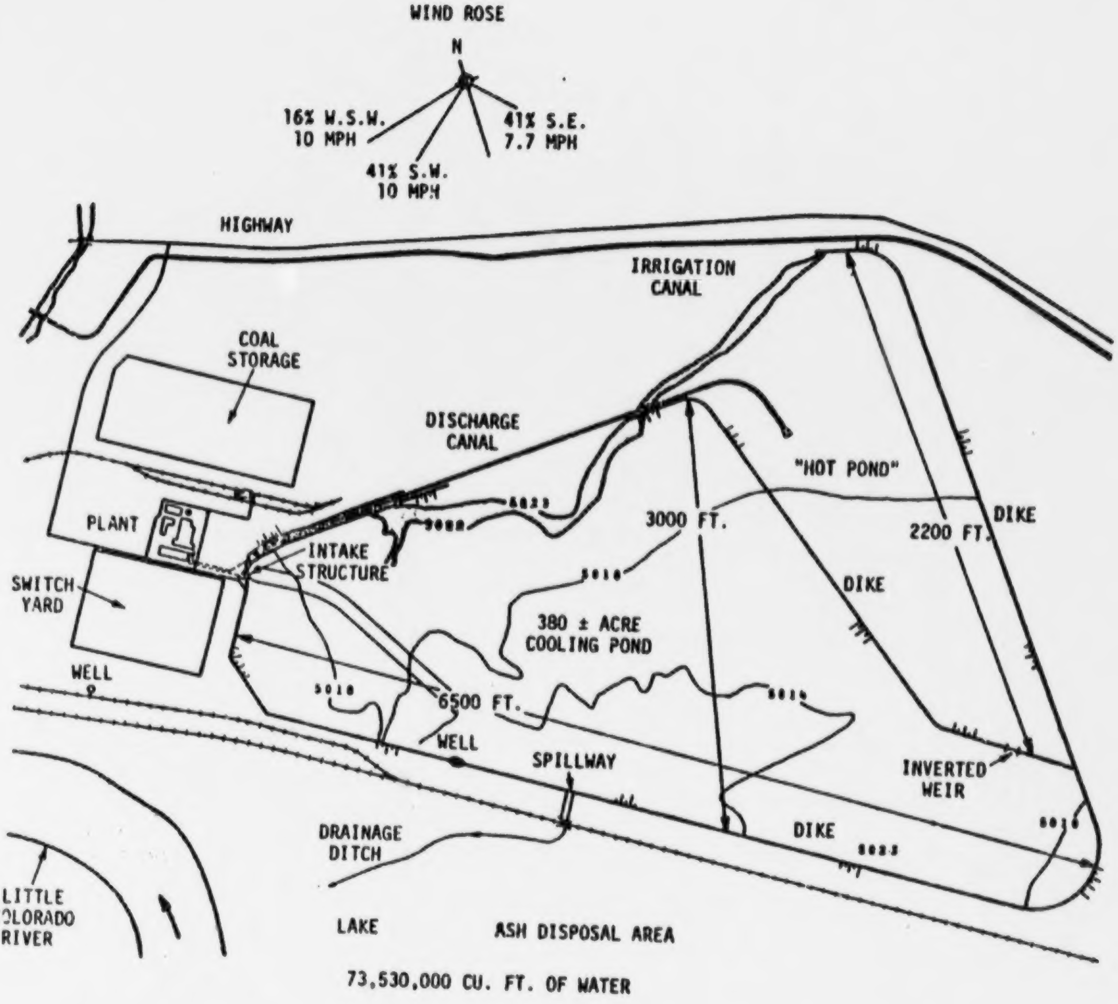

WIND ROSE
N
16% W.S.W.
10 MPH
41% S.W.
10 MPH
41% S.E.
7.7 MPH
HIGHWAY
IRRIGATION CANAL
COAL STORAGE
DISCHARGE CANAL
"HOT POND"
PLANT
INTAKE STRUCTURE
3000 FT.
2200 FT.
DIKE
DIKE
SWITCH YARD
380 ± ACRE COOLING POND
WELL
6500 FT.
WELL
SPILLWAY
INVERTED WEIR
DIKE
DRAINAGE DITCH
LITTLE COLORADO RIVER
LAKE
ASH DISPOSAL AREA
73,530,000 CU. FT. OF WATER

Figure 4.13. Cholla site development plan(29).

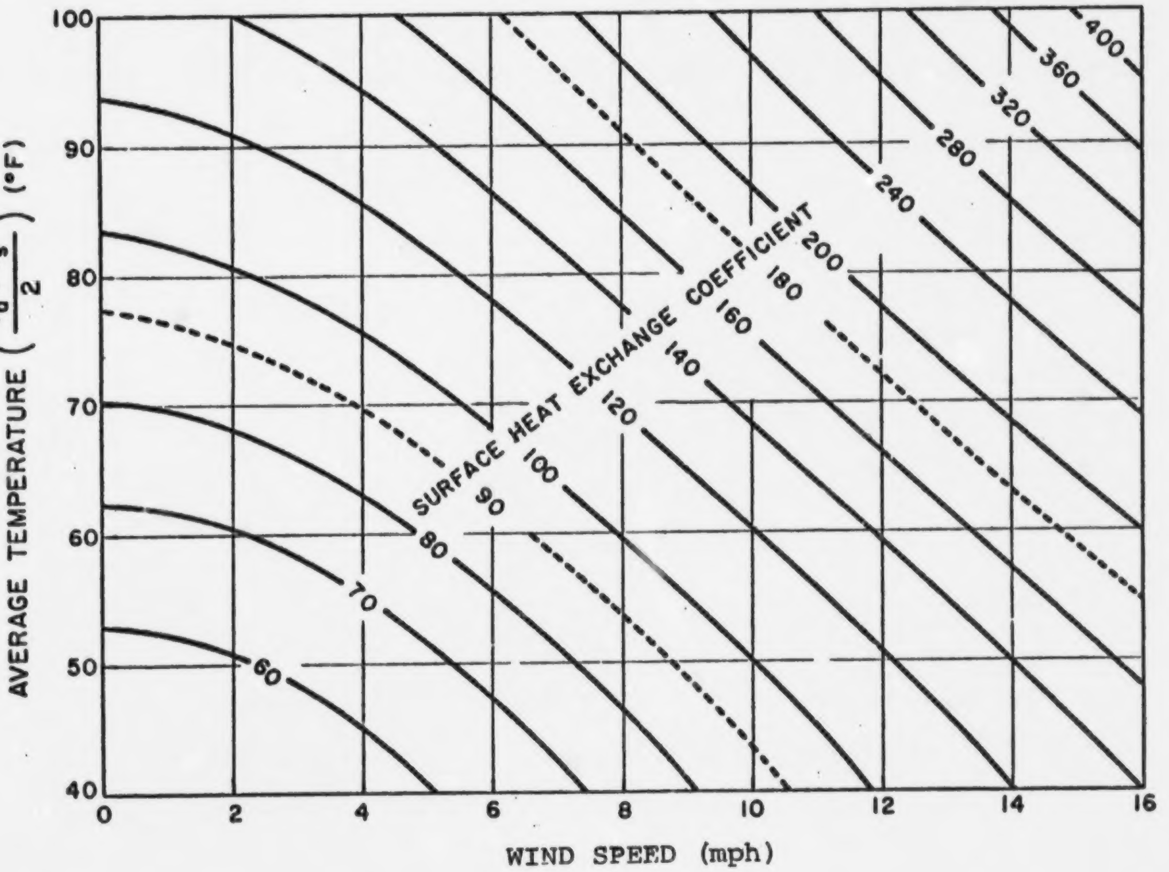


Figure 4.14. Design surface heat exchange coefficient for cooling ponds(23).

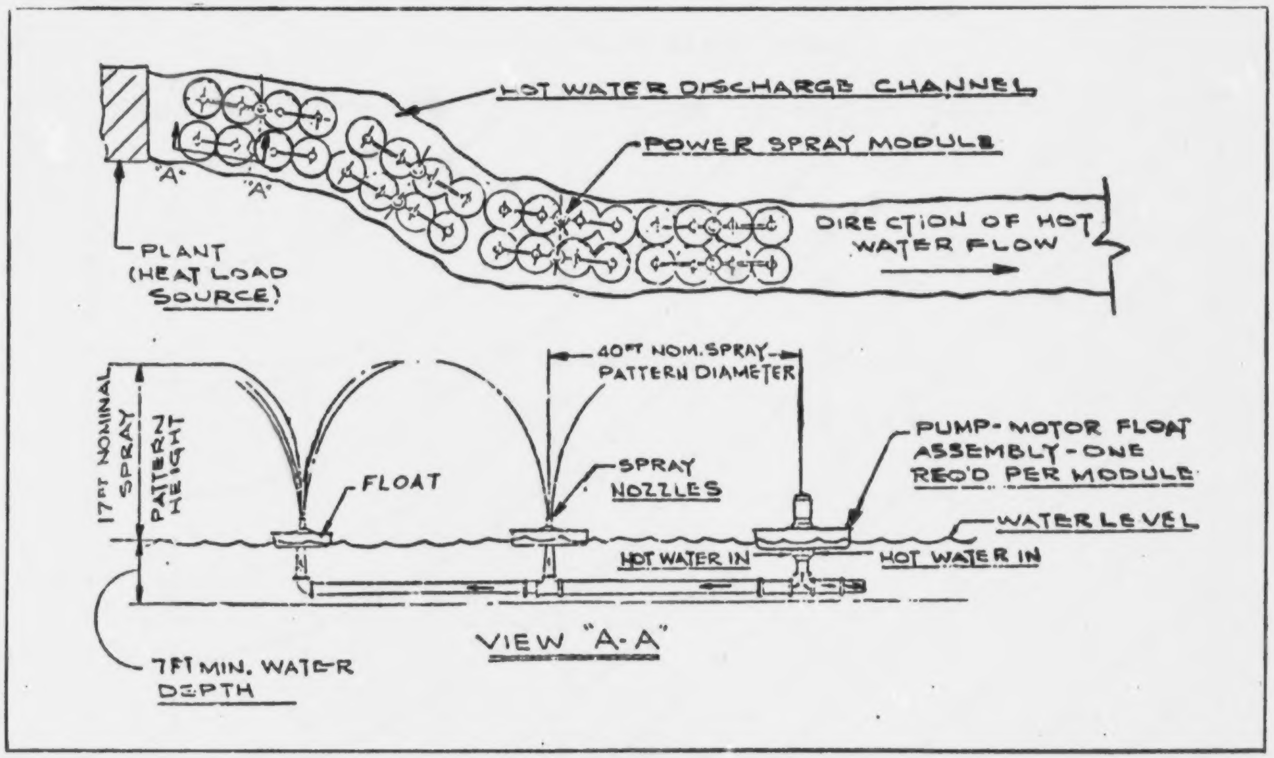

HOT WATER DISCHARGE CHANNEL
POWER SPRAY MODULE
"A"
"A"
PLANT (HEAT LOAD SOURCE)
DIRECTION OF HOT WATER FLOW
40FT NOM. SPRAY PATTERN DIAMETER
17FT NOMINAL SPRAY PATTERN HEIGHT
FLOAT
SPRAY NOZZLES
PUMP-MOTOR FLOAT ASSEMBLY-ONE REQ'D PER MODULE
WATER LEVEL
HOT WATER IN
HOT WATER IN
VIEW "A-A"
7FT MIN. WATER DEPTH

Figure 4.15. Typical power spray canal system with power spray module details(39).

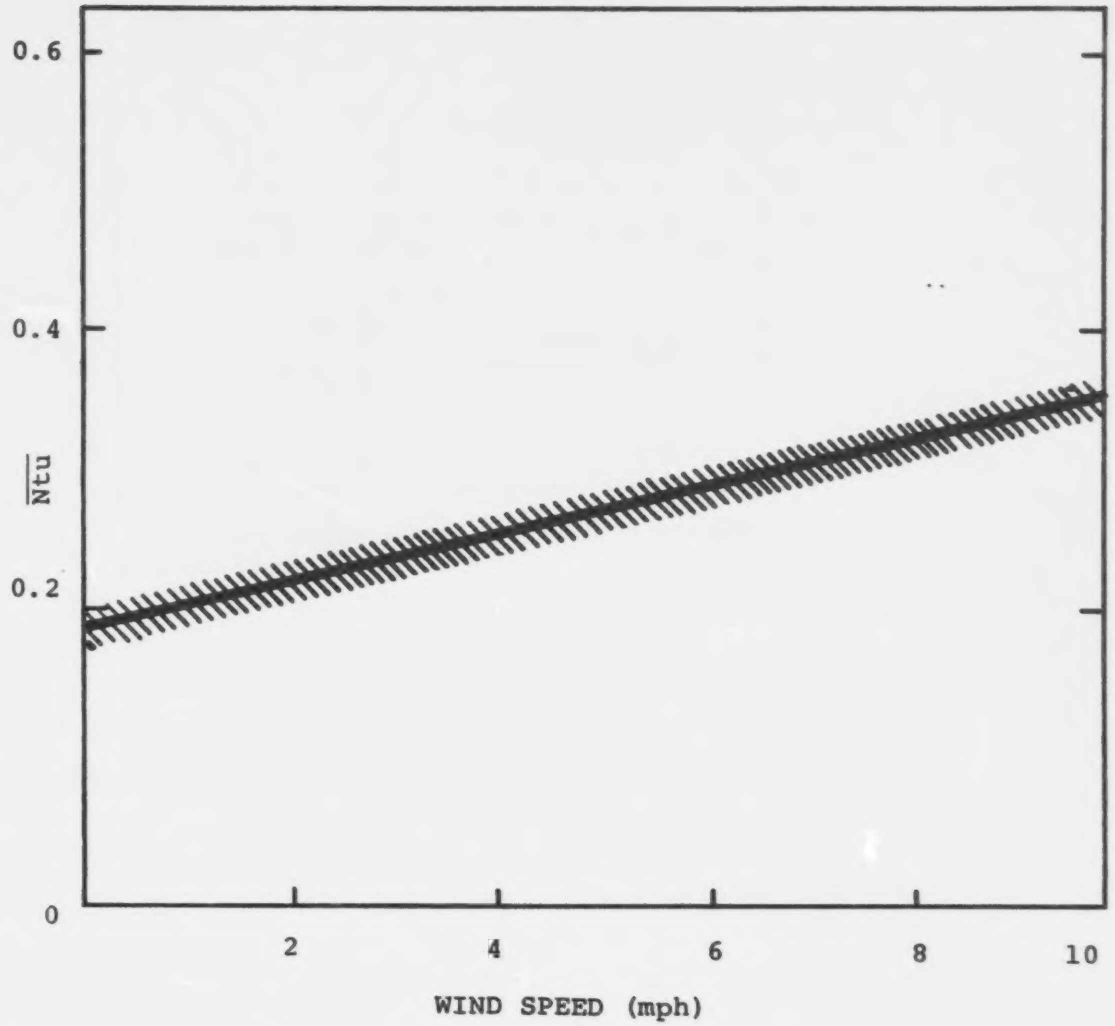


Figure 4.16. $\overline{Ntu}$ determined from tests on a single spray module(34). Reprinted from American Power Conference, 1976, by P. J. Ryan and D. M. Myers with permission of the American Power Conference.

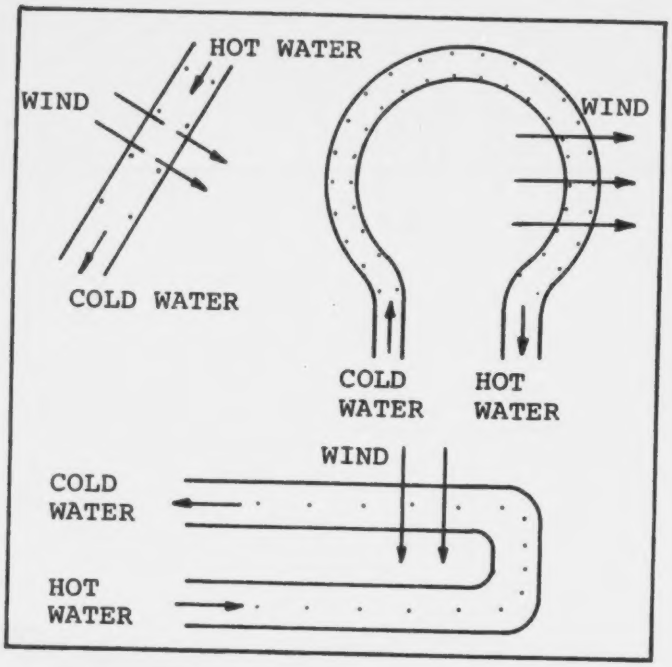

HOT WATER
WIND
COLD WATER
WIND
COLD WATER
HOT WATER
WIND
COLD WATER
HOT WATER

Figure 4.17. Possible spray cooling system configuration(37).

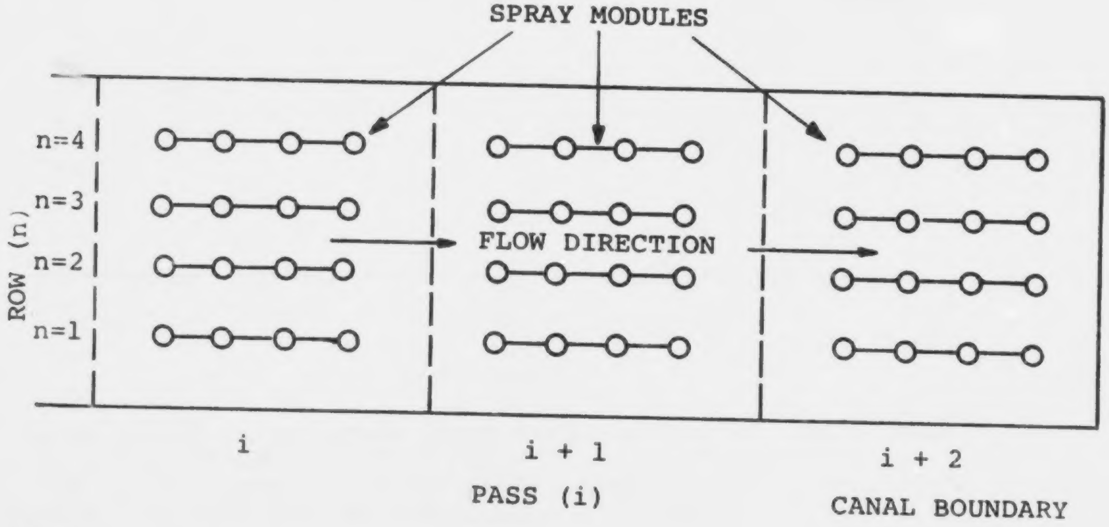

SPRAY MODULES
n=4
n=3
n=2
n=1
ROW (n)
FLOW DIRECTION
i
i + 1
i + 2
PASS (i)
CANAL BOUNDARY

Figure 4.18. Control volume for sizing spray canal systems.

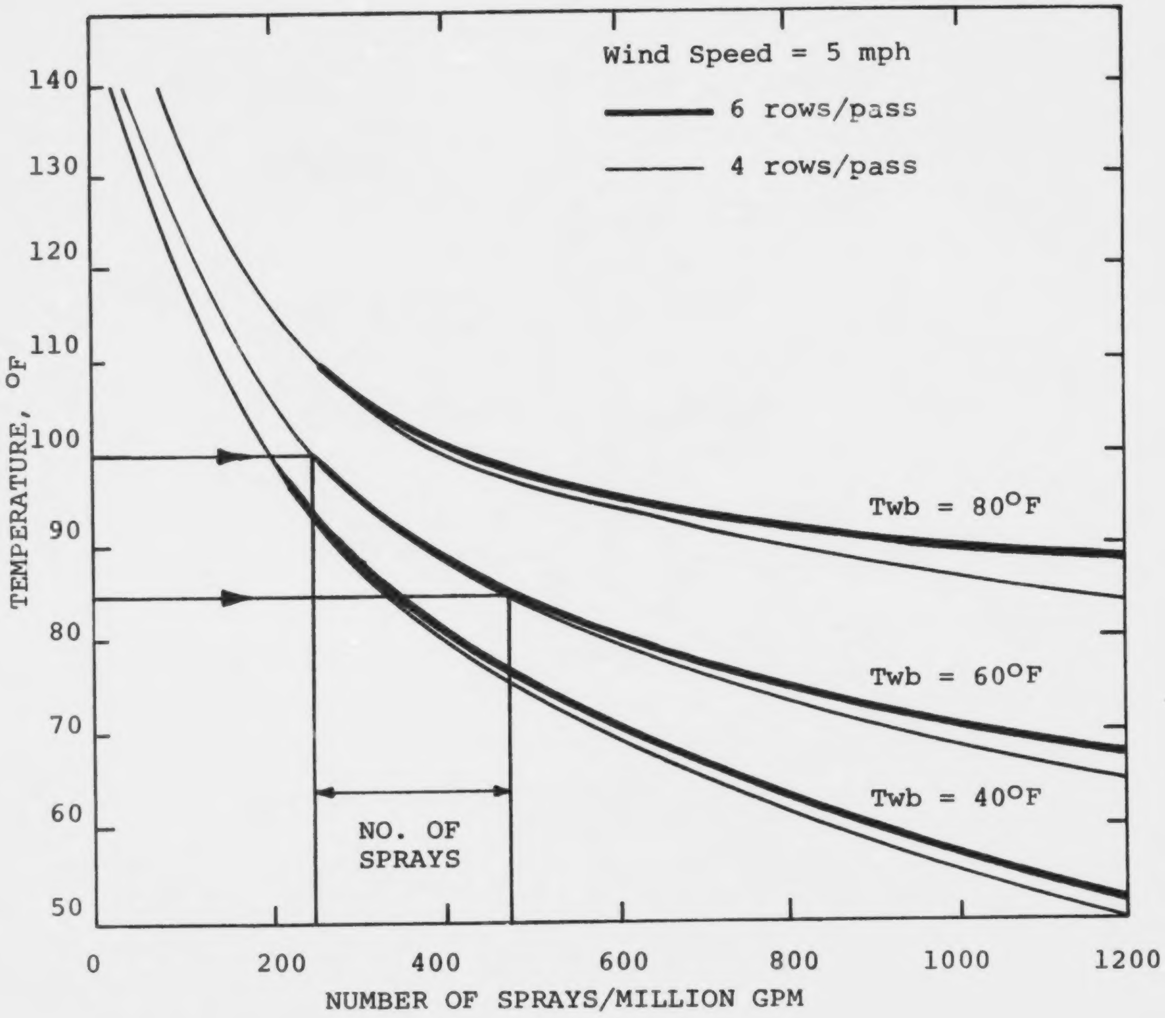


Figure 4.19. Design Curves for Sizing Spray Canal Systems(34). Reprinted from American Power Conference, 1976, by P. J. Ryan and D. M. Myers with permission of the American Power Conference.

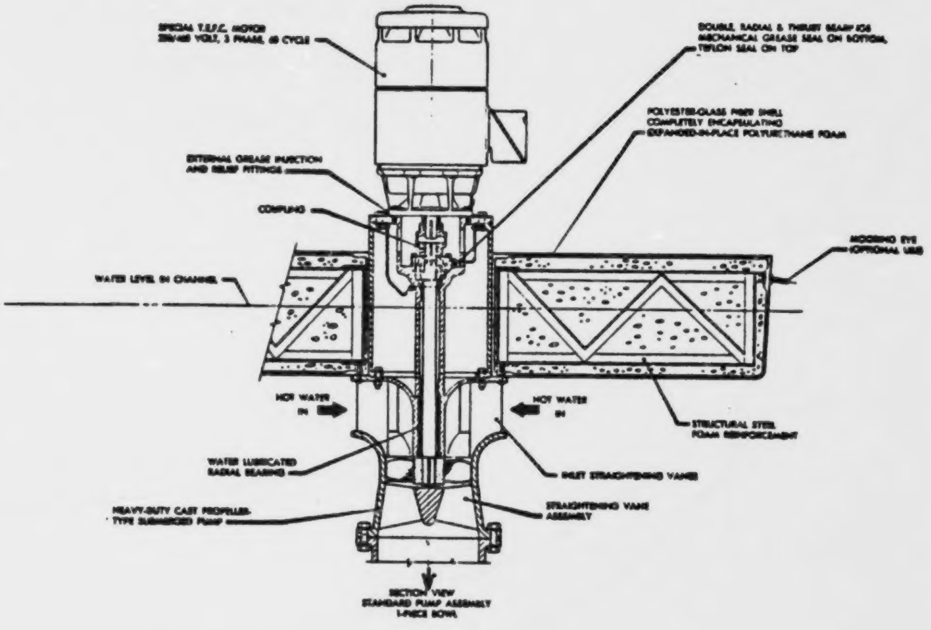
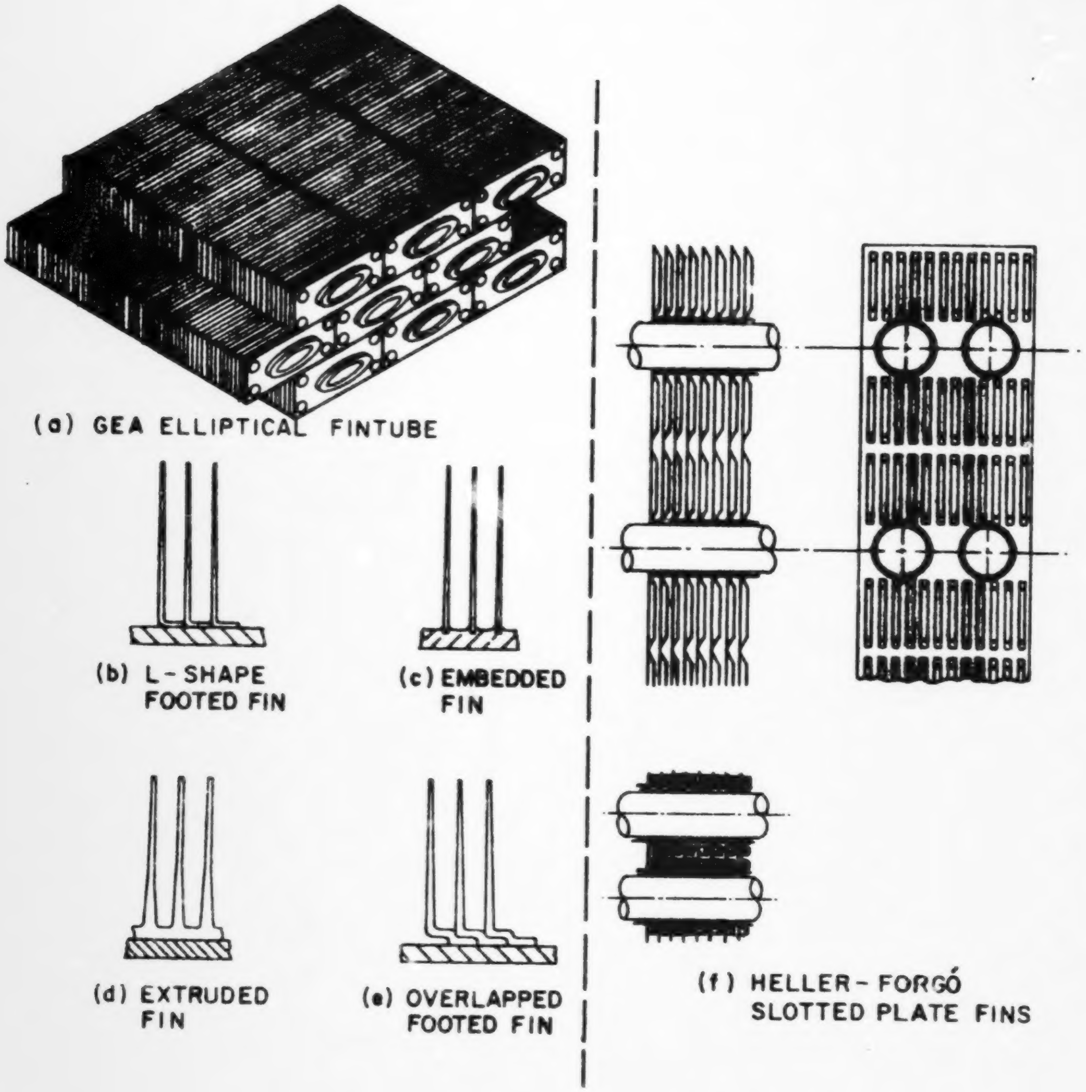

SPECIAL T.E.F.C. MOTOR
230/460 VOLT, 3 PHASE, 60 CYCLE
DOUBLE, RADIAL & THRUST BEARINGS
MECHANICAL GREASE SEAL ON BOTTOM,
TEFLON SEAL ON TOP
POLYESTER-GLASS FIBER SHELL
COMPLETELY ENCAPSULATING
EXPANDED-IN-PLACE POLYURETHANE FOAM
EXTERNAL GREASE INJECTION
AND RELIEF FITTINGS
COUPLING
MOORING EYE
(OPTIONAL USE)
WATER LEVEL IN CHANNEL
HOT WATER
IN
HOT WATER
IN
STRUCTURAL STEEL
FOAM REINFORCEMENT
WATER LUBRICATED
RADIAL BEARING
INLET STRAIGHTENING VANES
HEAVY-DUTY CAST PROPELLER-
TYPE SUBMERGED PUMP
STRAIGHTENING VANE
ASSEMBLY
SECTION VIEW
STANDARD PUMP ASSEMBLY
1-PIECE BOWL

Figure 4.20. Typical pump-motor-float assembly for spray modules(39).



(a) GEA ELLIPTICAL FINTUBE

(b) L-SHAPE FOOTED FIN

(c) EMBEDDED FIN

(d) EXTRUDED FIN

(e) OVERLAPPED FOOTED FIN

(f) HELLER-FORGÓ SLOTTED PLATE FINS

Figure 4.21. Types of fin-tube construction(40).

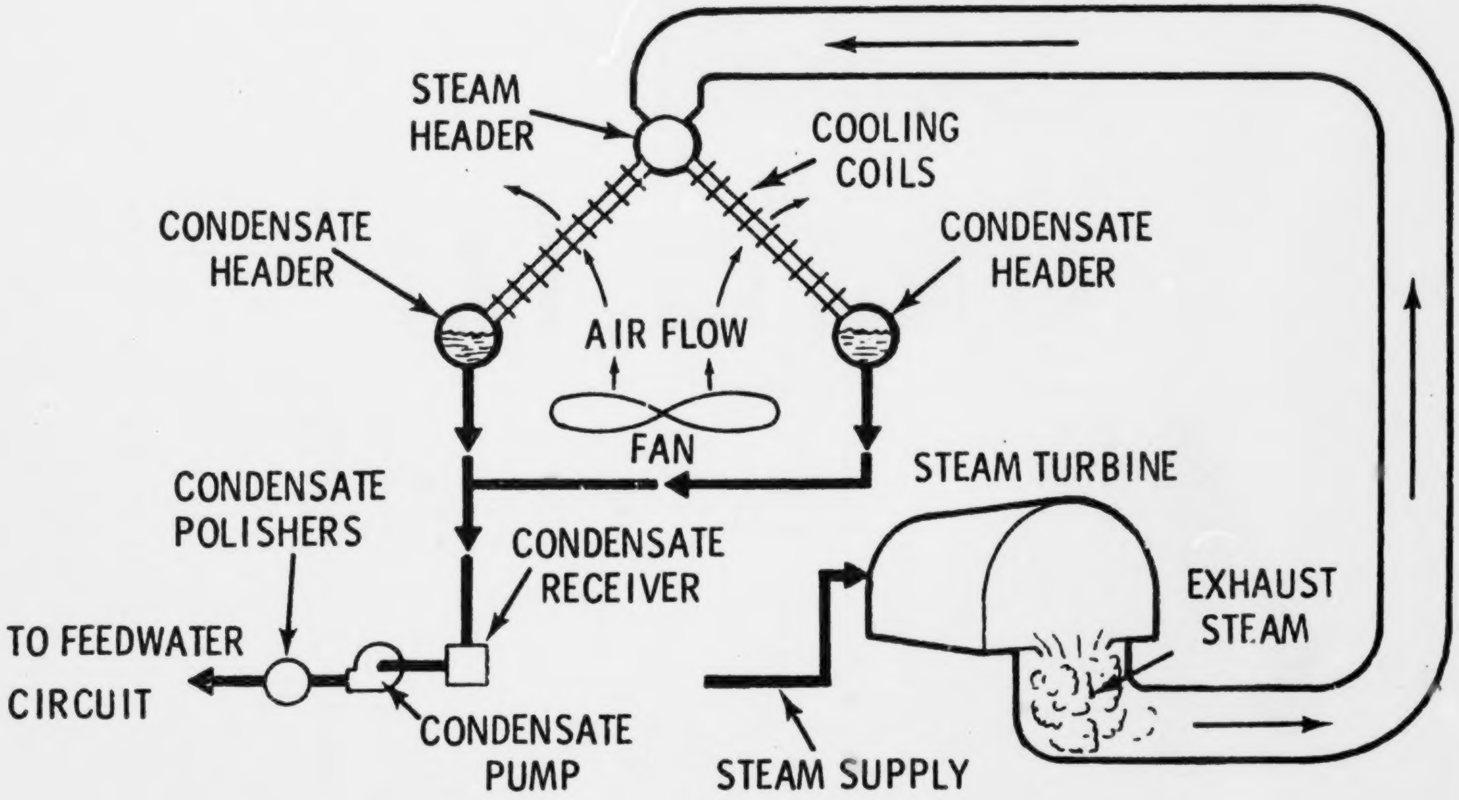

STEAM HEADER
COOLING COILS
CONDENSATE HEADER
CONDENSATE HEADER
AIR FLOW
FAN
STEAM TURBINE
CONDENSATE POLISHERS
CONDENSATE RECEIVER
EXHAUST STEAM
TO FEEDWATER CIRCUIT
CONDENSATE PUMP
STEAM SUPPLY

Figure 4.22. Direct, dry cooling tower condensing system with mechanical draft tower.

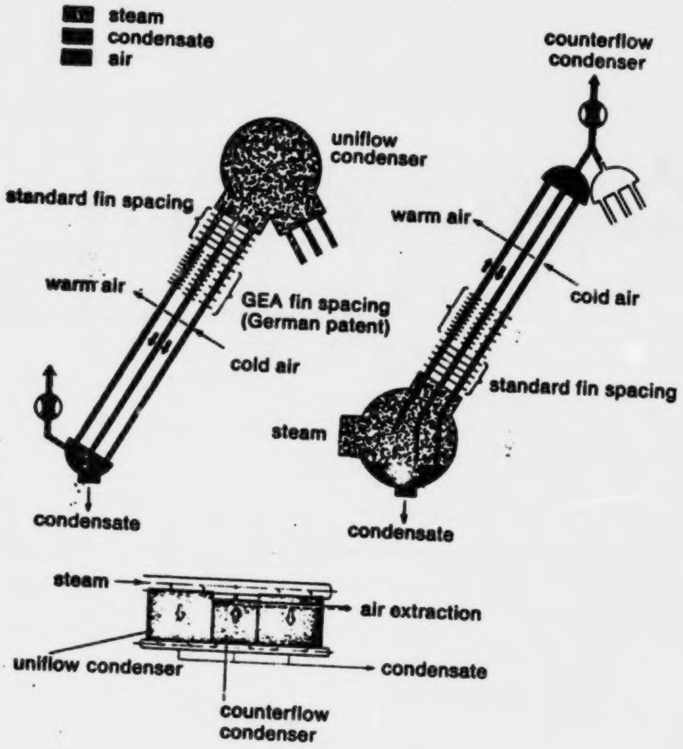

steam
condensate
air
uniflow condenser
standard fin spacing
warm air
GEA fin spacing (German patent)
cold air
condensate
counterflow condenser
warm air
cold air
standard fin spacing
steam
condensate
steam
air extraction
uniflow condenser
condensate
counterflow condenser

Figure 4.23. Condenser elements for direct dry cooling system(45).

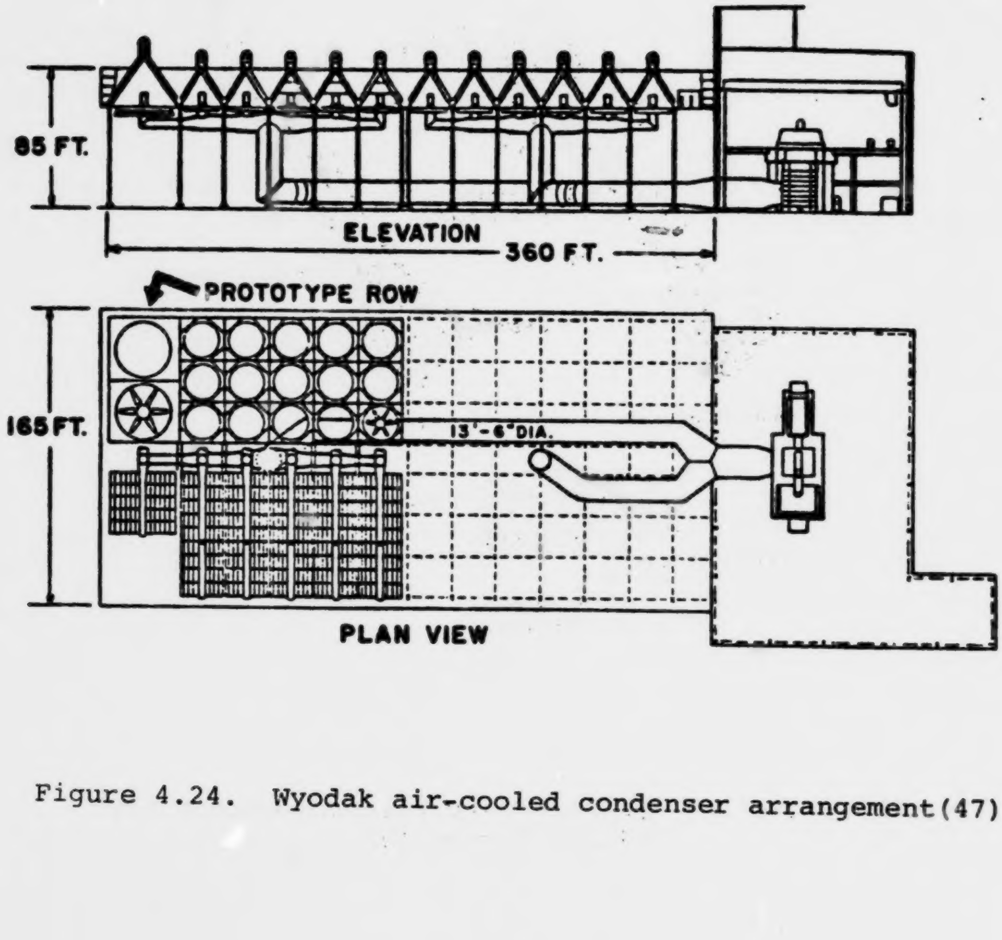

85 FT.
ELEVATION
360 FT.
PROTOTYPE ROW
165 FT.
13'-6" DIA.
PLAN VIEW

Figure 4.24. Wyodak air-cooled condenser arrangement(47).

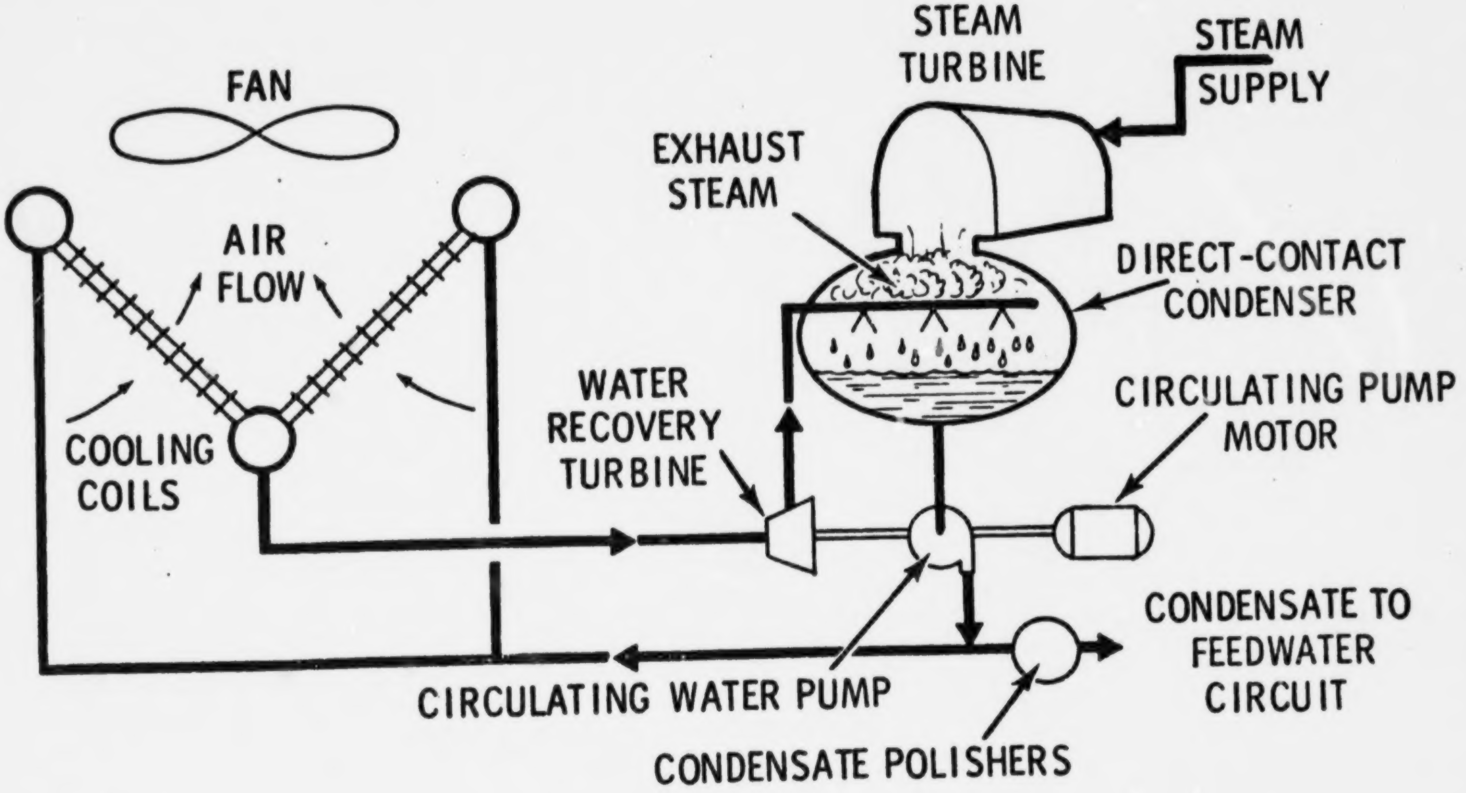

STEAM TURBINE
STEAM SUPPLY
FAN
EXHAUST STEAM
AIR FLOW
DIRECT-CONTACT CONDENSER
WATER RECOVERY TURBINE
CIRCULATING PUMP MOTOR
COOLING COILS
CONDENSATE TO FEEDWATER CIRCUIT
CIRCULATING WATER PUMP
CONDENSATE POLISHERS

Figure 4.25. Indirect, dry cooling tower system with direct contact (spray) condenser (Heller system).

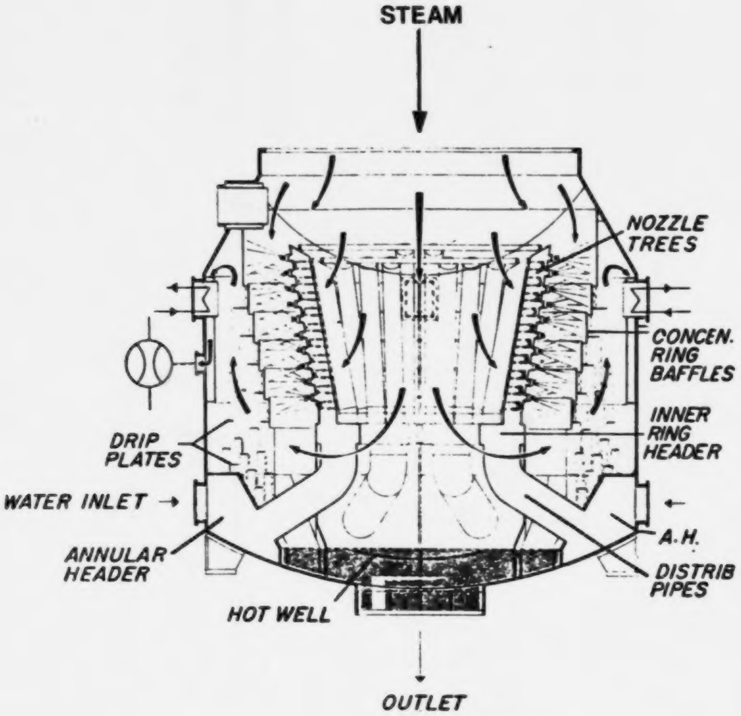

STEAM
NOZZLE TREES
CONCEN. RING BAFFLES
INNER RING HEADER
DRIP PLATES
WATER INLET →
A.H.
ANNULAR HEADER
DISTRIB PIPES
HOT WELL
OUTLET

Figure 4.26. Typical spray condenser(49).

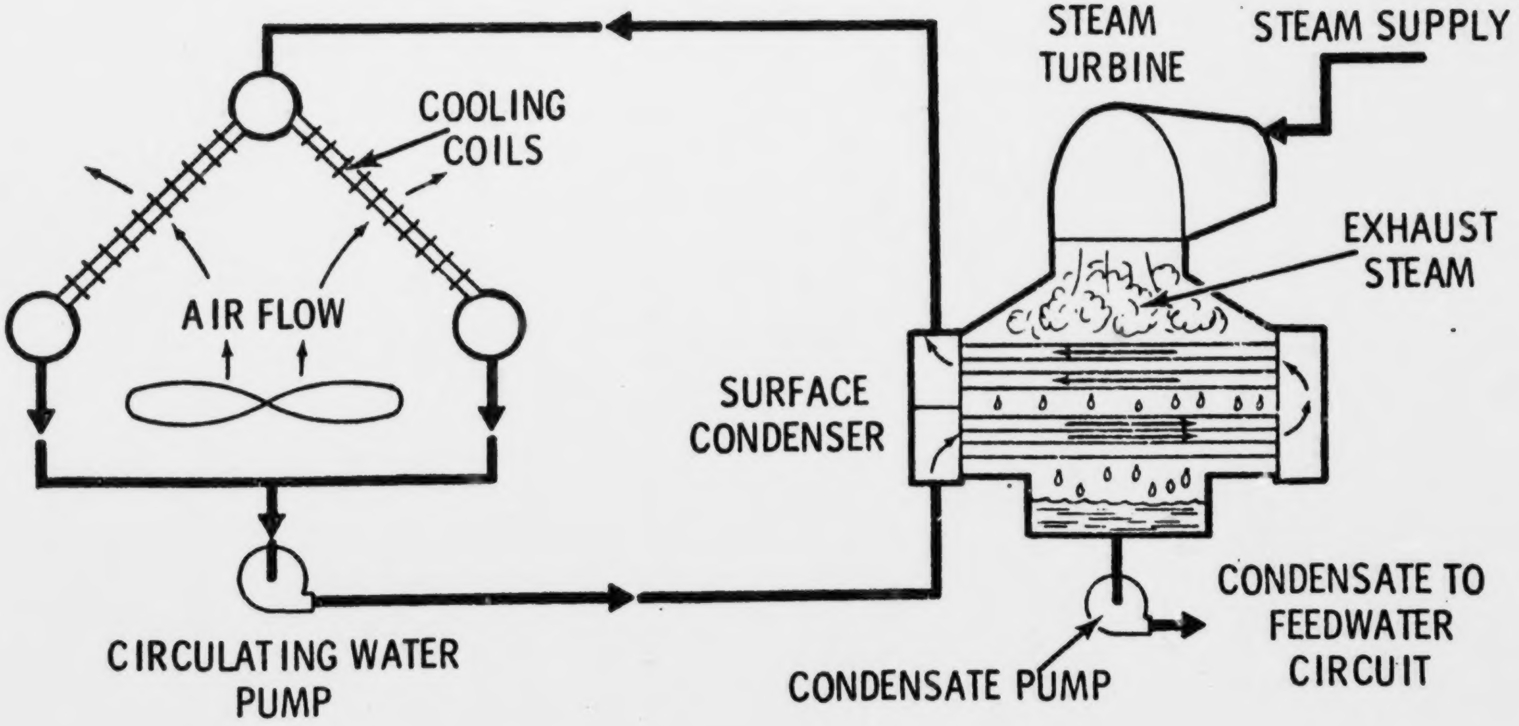
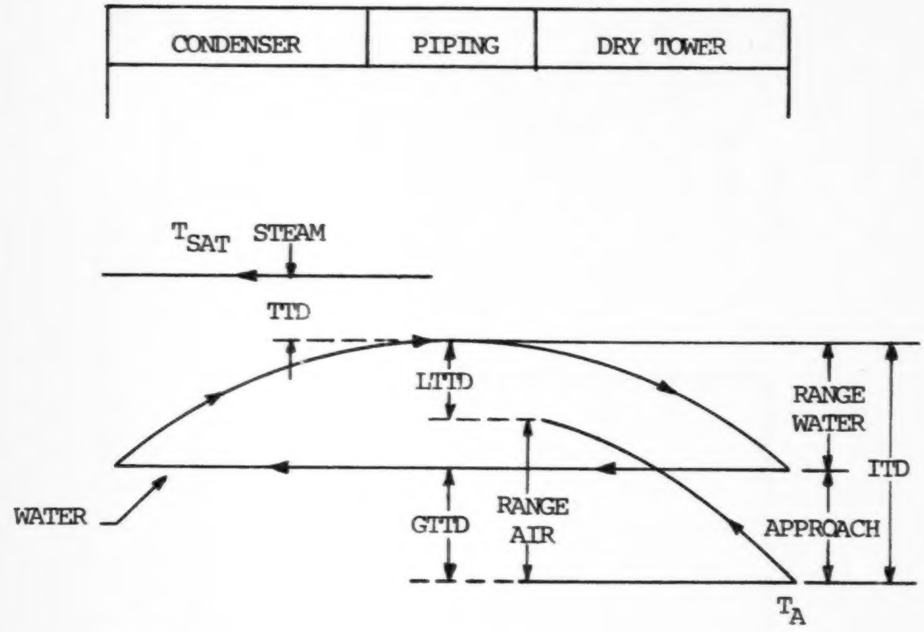

STEAM TURBINE
STEAM SUPPLY
COOLING COILS
EXHAUST STEAM
AIR FLOW
SURFACE CONDENSER
CONDENSATE TO FEEDWATER CIRCUIT
CIRCULATING WATER PUMP
CONDENSATE PUMP

Figure 4.27. Indirect, dry cooling tower system with surface condenser.


CONDENSER
PIPING
DRY TOWER
TSAT
STEAM
TTD
LTTD
RANGE WATER
ITD
WATER
GTTD
RANGE AIR
APPROACH
TA

T_{SAT} = turbine exhaust temperature.

TTD = terminal temperature difference.

ITD = initial temperature difference.

T_A = ambient dry bulb design temperature.

LTTD = lesser terminal temperature difference between water and air.

GTTD = greater terminal temperture difference between water and air.

Figure 4.28. Temperature diagram of indirect dry tower.

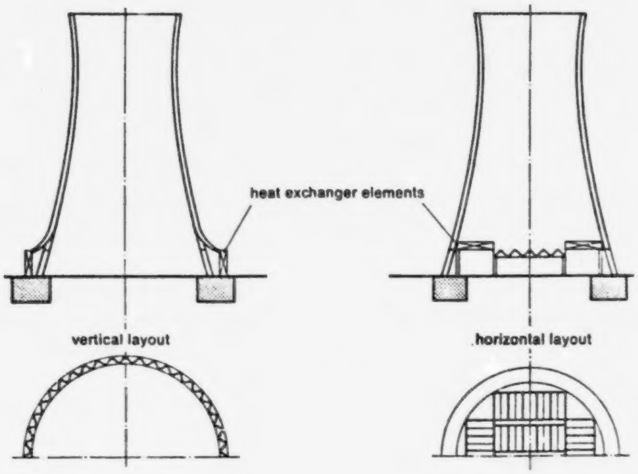
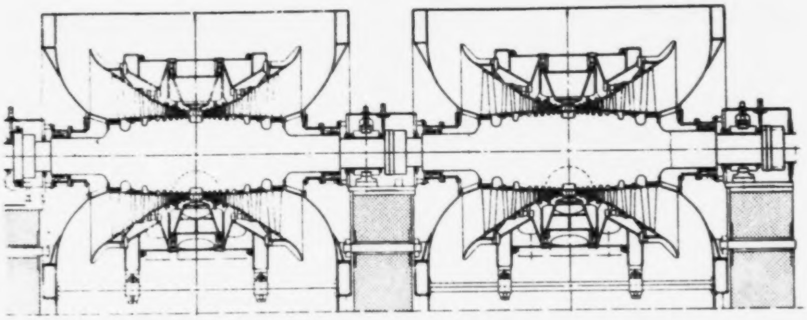
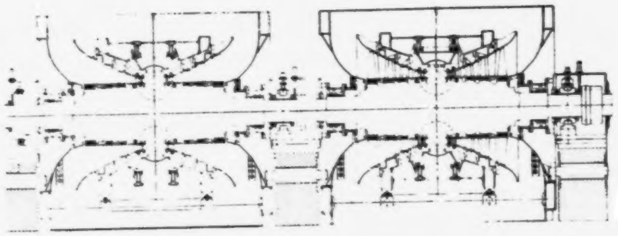

heat exchanger elements
vertical layout
horizontal layout

Figure 4.29. Schematic tower designs with horizontal and vertical tube layouts.



Conventional



High back pressure

Figure 4.30. Size comparison between high back pressure and conventional turbine of approximately equal power rating(48). Reprinted from Power Engineering, 1977, by M. O. Surface with permission of Technical Publishing Company.

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SECTION 5

NEAR HORIZON COOLING SYSTEMS

5.1 INTRODUCTION

Through the years, many different types of systems have been developed and used for dissipating waste heat from steam-electric power plants. The systems in current use are classified in this manual as conventional closed-cycle cooling systems and have been described in Section 4. In practice, it has been advantageous to combine some of these systems to lessen or eliminate the environmental impacts of the component systems while maintaining the performance and cost of the new system at an acceptable level.

The integration of wet towers and dry towers to form a combined system is especially attractive. These combinations, called wet/dry cooling towers, can be used either for plume abatement or for water conservation(1-7). Although there are no major operating power plants using these wet/dry systems, one wet/dry tower system for plume abatement has been purchased by the Baltimore Gas & Electric Company for the Brandon Shore Station(8), and two wet/dry tower systems for water conservation have been purchased by the Public Service Company of New Mexico for its San Juan Units No. 3 and 4(9).

In a wet/dry tower for plume abatement, the wet section is the basic heat rejection device. The dry section is needed to reduce the relative humidity of the air leaving the wet tower, thereby reducing the probability of fogging when ambient temperatures are low and humidity conditions are high. The current design of wet/dry towers for plume abatement has a small dry section positioned above the wet section within a single structure. These wet/dry towers have been designated in the cooling tower industry as "hybrid" wet/dry towers.

In a wet/dry tower for water conservation, the dry section is the basic heat rejection device. The wet section is needed to augment the heat rejection capability of the dry tower at high ambient conditions, thereby reducing the turbine back pressures to levels where existing steam turbines can be used.

The current design of wet/dry towers for water conservation has wet and dry towers joined by a circulating water circuit.

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The component wet and dry towers can be structurally and functionally separated, such as the wet/dry towers evaluated in Reference 10 and 11. They also can be structurally integrated but functionlly separated, such as the wet/dry towers designed by the Marley Company for the San Juan Units No. 3 and 4(9). Since the wet and dry towers are functionally separated, the wet tower can be removed from service when the ambient temperature falls, and the dry tower can reject all the plant waste heat.

Two studies performed for the Federal Government have evaluated these two concepts in significant detail(10,11). The information provided in the next two sections is based on these two studies.

5.2 WET/DRY TOWERS FOR PLUME ABATEMENT

5.2.1 General Description

The wet/dry mechanical draft cooling tower for plume abatement is schematically depicted in Figure 5.1. These towers have been designated hybrid wet/dry towers. The cooling tower consists of a conventional wet fill section with finned dry heat exchangers positioned above the fill. The dry heat exchangers can be either the film type in which water flows inside of the tube walls in a thin film(2) or the full flow type in which water fills the tube(1). The air flows through the wet and dry sections in parallel, whereas the water flows through the two sections in series. The hot water from the condenser passes through the dry section first, and then falls through the evaporative fill. In most cases, only a portion of the total circulating water travels through the dry section, while at all times during tower operation, the entire flow of water is in the wet section. The air flow through both the dry and wet sections is varied by means of dampers in both sections.

The purpose of using the hybrid parallel path (air flow) wet/dry tower is to decrease the tower-induced fog. Fog is a condition when the water vapor in the tower plume or atmospheric air condenses and reduces the visibility to about a quarter mile (11) or less. The dry section functions to decrease the relative humidity of the air leaving the tower by adding warm, unsaturated air to the saturated or near saturated exhaust air from the wet section. The principles of operation of wet/dry towers for plume abatement are described psychrometrically in the next section.

5.2.2 Principles of Wet/Dry Tower Operation for Plume Abatement(8)

A wet mechanical tower is schematically depicted in Figure

5.2; its operation is depicted on the psychrometric chart, Figure 5.3. The ambient air absorbs heat and moisture via evaporative heat transfer as it contacts the water in the fill section of the tower. The air leaves the fill section and exits from the fan discharge stack at state 2. The air leaving the tower mixes with the ambient air along the linear process line 1-2 shown on the psychrometric chart. Depending on the condition of the ambient air, the process line from state 2 to state 1 can pass through the supersaturation region as shown in Figure 5.3. When this occurs and mist or water droplets are formed, the plume leaving the cooling tower is visible and will not be dissipated until the plume entrains sufficient ambient air to make the plume unsaturated and invisible.

When a mechanical draft wet tower is located in an area in which the ambient air is frequently not able to readily absorb the additional moisture added by the cooling tower, potential fogging problems occur. This ambient condition, coupled with the fact that the air leaves a mechanical draft wet tower at heights of only 40 to 60 feet (12.2 to 18.3 meters) above the ground, increases the risk of fogging at ground level.

A hybrid mechanical draft wet/dry cooling tower with film-type dry section is shown schematically in Figure 5.4; its operation is shown on the psychrometric chart, Figure 5.5.

The hybrid wet/dry towers have finned-tube heat exchanger modules in the dry section mounted atop the conventional wet section. The air flow through the wet and dry sections is in parallel, while the water flow is in series. Hot water is delivered to the manifold atop the tower, which in turn distributes the water to the tubes. The water flows through the dry section and then into the wet section. The air flow through both sections is varied by means of dampers in each section.

As shown in Figures 5.4 and 5.5, ambient air at state 1 is taken into the tower through both the wet and dry sections (assuming dampers in both sections are open). The ambient air entering the wet section absorbs heat and moisture as in a conventional wet tower. The air leaves the wet section at state 2. The ambient air entering the dry section, state 1, absorbs heat (no moisture) as a result of sensible heat transfer and leaves the dry section at state 3. The air streams leaving both sections mix in the plenum chamber to achieve state 4 before leaving the fan discharge stack. The air leaving the tower at state 4 mixes with the ambient air along a process line between state 4 and state 1. The condition of the air at state 4 depends on the mass flow rates of air flowing through the wet and dry sections and the temperatures at states 2 and 3. If more of the total mass flow rate of air is put through the dry section, state 4 will be closer to state 3 than to state 2 and conversely. During ambient conditions conducive to fogging, enough air must be put through the dry section such that the mixing line between state 4 and state 1 falls to the right of the supersaturation region on the psychrometric chart. Under these circumstances, the fogging potential for the plume is decreased or eliminated.

In general, the wet/dry operating mode of the tower will be limited to only those occasions when the ambient conditions are conducive to fogging, since operation in the wet/dry mode is less efficient than operation in the wet mode. The controlled operation can be accomplished through the use of meteorological monitoring and control systems which are connected to the plant's computer system. A monitoring and control system designed for this purpose is described in Reference 8.

5.2.3 Plume Temperature and Moisture Content of the Wet/Dry Tower Plume

As discussed in Section 5.2.2, the purpose of the wet/dry tower is to exhaust a mixture of air and water vapor to the atmosphere at a temperature and relative humidity which are low enough, so that upon cooling, the vapor which condenses will not cause any fog-related problems in the near vicinity of the tower. For control of fog-related problems, the maximum allowable moisture content of the exhaust air will change as the ambient condition changes. A criterion on the time limit of fogging must be established in order to determine the relative sizes of the wet and dry sections of the cooling tower.

The condition of the exit air can be given by the air temperatures across the wet and dry sections and the air flow rates through each section. The air and vapor mixture coming through each section mixes in the plenum chamber underneath the fan and as it passes through the fan. A mass balance on the vapor and the dry air and an energy balance on the mixing air streams are required before determining the relative humidity of the exit air stream. For steady state flows, the mass balance for dry air is:

$$Q_d \, (\rho_a)_d + Q_w \, (\rho_a)_w = Q_p \, (\rho_a)_p \qquad (5.1)$$

where:

Q_d = volumetric flow rate of the air-vapor mixture entering the plenum chamber from the dry section, m^3/s.

Q_w = volumetric flow rate of the air-vapor mixture entering the plenum chamber from the wet section, m^3/s.

Q_p = volumetric flow rate of the air-vapor mixture leaving the plenum chamber and passing through the fan, m^3/s.

$(\rho_a)_w$ = density of dry air leaving the wet section, Kg/m^3.

$(\rho_a)_d$ = density of dry air leaving the dry section, Kg/m^3.

$(\rho_a)_p$ = density of dry air leaving the plenum chamber, Kg/m^3.

Assuming the air leaving the wet section is saturated, a mass balance on the water vapor entering and leaving the plenum chamber under steady state operation gives:

$$Q_d\ (\rho_a)_d\ W + Q_w\ (\rho_a)_w\ W_w = Q_p\ (\rho_a)_p\ W_p \qquad (5.2)$$

where:

W = specific humidity of the ambient air, Kg of water vapor/Kg of dry air.

W_w = specific humidity of the air leaving the wet section, Kg of water vapor/Kg dry air.

W_p = specific humidity of the mixed streams, Kg of water vapor/Kg dry air.

Assuming that the mixing process which takes place in the plenum chamber is adiabatic, an energy balance gives:

$$Q_d\ (\rho_a)_d\ H_d + Q_w\ (\rho_a)_w\ H_w = Q_p\ (\rho_a)_p\ H_p \qquad (5.3)$$

where:

H_d, H_w, and H_p are the enthalpies (KJ/Kg of dry air) of the air-vapor streams leaving the dry section, the wet section, and the plenum area, respectively.

The kinetic and potential energies of the air-vapor streams are neglected since the velocities and elevation changes remain relatively small.

The enthalpy of the air-vapor mixture entering the plenum chamber will depend on the relative performance of the wet and dry sections. Knowing the performance of each section, the specific humidity and the enthalpy of the mixture are found from Equations (5.1) through (5.3). Once the specific humidity leaving the plenum chamber and the enthalpy of the mixture in the plenum chamber are known, the wet and dry bulb temperatures can be found on a psychrometric chart.

5.2.4 Design of Wet/Dry Towers for Plume Abatement

As previously indicated, the hybrid wet/dry tower is operated in a wet/dry mode only at ambient conditions conducive to fogging or icing by the tower plume. The ambient conditions which fall in this category are low dry bulb temperature, high relative humidity, and low wind speed. As a result, the hybrid wet/dry tower modules are generally designed with regular wet tower modules as the base. On top of each wet section, a dry heat exchanger is added to form a hybrid wet/dry tower module.

A detailed design and cost study of the hybrid wet/dry tower gives the following design procedure for sizing wet/dry tower systems(11). In the first step, different wet tower systems are designed to handle the plant heat load by varying the wet tower approach and the cooling range. The tower systems are then evaluated for thermal performance, capital and penalty costs, as well as fogging potential. Using these wet tower systems, all of the systems with the same fogging potential are identified, and the minimum cost system is selected as the optimum system for each specified fogging potential. An optimized wet tower system selected solely on the basis of economics is referred to as the reference system. The fogging potential is defined as the number of hours the cooling tower plume may interact with the ambient air and cause ground level fog which limits visibility to less than 0.25 miles. (An ambient condition with visibility less than 0.25 miles is considered to be heavy fog). The fogging potential can be determined by various plume analysis models(11).

In the second step, the cooling systems using hybrid wet/dry towers with varying dry section sizes are evaluated in a similar manner, with the exception that the plume abatement analyses should be performed for the wet/dry operating mode. The minimum cost hybrid wet/dry system is then identified for each specified fogging potential.

In the third and final step, the minimum cost systems obtained in the above two steps for wet and wet/dry systems for each specified fogging potential are compared, and the minimum cost system is identified as the optimized system for the specified fogging potential.

5.2.5 Typical Size, Performance and Cost of Wet/Dry Tower Systems for Plume Abatement

Typical size, performance and cost of the hybrid wet/dry tower systems designed for plume abatement are shown in Table 5.1 and in Figure 5.6. The size, performance, and costs are given in terms of number of modules and dry section height, number of ground fogging hours, and the capital, penalty and total evaluated costs, respectively. (Full flow dry heat exchange modules were used). These data were taken from Reference 11. The conclusions drawn from these data are:

1. Although the hybrid tower system does provide an effective means for reducing ground fogging from low profile mechanical towers, ground fogging can also be reduced by simply increasing the wet tower size.
2. In most circumstances, a hybrid tower system is more costly than a comparable wet tower system with equal fogging potential (Figure 5.6). As such, the use of a hybrid wet/dry tower system is not recommended in these cases. However, special site consideration, e.g., existing sites which are to be backfitted to closed-cycle cooling, may require the use of hybrid wet/dry towers because of space constraints.

5.3 WET/DRY TOWERS FOR WATER CONSERVATION

5.3.1 General Description

A number of possible arrangements exist for combining separate wet and dry towers into wet/dry towers which can conserve make-up water while rejecting the power plant waste heat. Many of these wet/dry towers have been described in the literature(3-5). Two designs which have been proposed by manufacturers are:

1) Mechanical Series Wet/Dry Tower

This system combines separate mechanical draft wet and dry towers into an operational unit by means of a cooling water circuit which flows through the dry and wet towers in series (Figure 5.7).

2) Mechanical Parallel Wet/Dry Tower

This system combines separate mechanical draft wet and dry towers into an operational unit by means of a cooling water circuit which flows through the wet and dry towers in parallel (Figure 5.8).

Analyses(10,11) have indicated that mechanical series and mechanical parallel wet/dry cooling for water conservation have approximately the same total evaluated cost and are similar in operation. For this reason and because the first commercial purchase has a series flow tower, only the series flow wet/dry system is discussed in this section.

5.3.2 Design and Operation of Series Flow Wet/Dry Towers for Water Conservation

The series wet/dry towers are usually designed such that water flows first to the dry tower and then to the wet cooling tower as shown in Figure 5.7.

The dry tower is designed to reject the entire heat load at a low ambient temperature while maintaining the turbine back pressure within specified limits. The performance of the dry tower is then evaluated at the peak ambient temperature condition to determine the maximum heat rejection capacity of the dry tower without exceeding the specified limiting back pressure. This information is then used to size the wet helper tower needed to reject the remaining heat load at this ambient temperature.

For this cooling system, the dry cooling is the basic heat rejection mechanism, and the wet cooling is used to provide supplementary heat rejection when necessary. The dry tower is designed to operate continuously during the year and provisions are included to shut down wet cells, if they are not needed at low ambient temperatures, depending on the wet/dry operating mode under which the system is designed to operate. Two different modes of operation analyzed in References 10 and 11 are described below:

1) Mode S1

The first mode is termed the S1 mode (S for series). The main objective of this mode is to operate the wet helper tower as little as practically possible. This mode of operation is illustrated schematically by means of a turbine back pressure characteristic of a wet/dry system operated in this mode (Figure 5.9). At the peak summer ambient temperature, both the wet and dry towers are operating at full capacity as indicated by point 1. As the ambient temperature falls, the wet cells are turned off in succession to maintain the turbine back pressure essentially constant at the wet tower design value. When point 2 is reached, all of the wet cells have been shut down, and the dry tower handles the entire heat load. The back pressure curve between points 1 and 2 is of a saw-tooth shape because a discrete number of wet cells are taken out of service as the ambient temperature falls. This operational mode requires continuous feedback controls for the operation of the wet towers. Most new stations are being designed with sufficient computer capacity to provide for this additional measure of station control.

2) Mode S2

The second mode of operation represents a system operating with much less control of the wet tower. The turbine back pressure characteristic resulting from the operation of a wet/dry system in this mode is illustrated in Figure 5.10. In this mode, all the wet cells are operated continuously until the dry tower design temperature is reached (point 2). As the ambient temperature decreases, the turbine back pressure is allowed to fall. When the ambient temperature drops to the point where the dry tower is sized to reject the entire heat load, the wet tower is turned off completely (point 2). As the ambient temperature passes through the dry tower design point, an apparent instantaneous jump in back pressure occurs (typically 0.5 to 2 in.Hg (13~50 mm Hg)). However, in reality, this transition would occur over a long enough time span so as not to create any damaging thermal shock to the turbine and associated equipment. Turbine manufacturers have indicated that changes in back pressures of this magnitude occur daily during the operating life of the turbine.

Wet/dry cooling systems operating in the S1 mode are more water conservative at the expense of greater energy consumption than the same system operating in the S2 mode. Conversely, systems operating in the S2 mode are more energy conservative at the expense of higher water consumption.

5.3.3 Design, Economics and Plant Performance of Wet/Dry Tower Systems for Water Conservation

5.3.3.1 Design and Cost--

The designs and costs of wet/dry tower systems for water conservation have been reported in Reference 10 to 19. Typical designs and costs of wet/dry tower systems sized for various water make-up requirements and the reference wet and dry tower systems for nominal 1000-MWe coal-fired plants are shown in Tables 5.2 and 5.3(11). The make-up requirement is expressed as a percentage of the annual make-up required by a comparable wet tower system in terms of heat rejection capability.

Table 5.2 shows a summary of these major design data for the wet/dry cooling systems. Included in this table are the tower size and operating mode, the maximum operating back pressure, the gross generator output, the condenser or tower heat load at the maximum back pressure, the heat load distribution between the wet and dry towers at the maximum back pressure, and the annual water make-up for the tower systems. All of the systems operate in Mode S1.

These data indicate that dry cooling tower systems of manageable size can be designed for utility application by peak shaving the heat load with evaporative helper towers. The number of cells needed for the wet/dry option are comparable to or less than that required for the dry cooling system using the high back pressure turbine. The data also show that the capacity deficit incurred with the use of the high back pressure turbine (119 MWe) can be reduced more than 69 MWe, even with the wet/dry system requiring two percent make-up.

Table 5.3 shows that the costs of wet/dry systems range between the dry and the wet systems; the costs of the wet/dry systems decrease monotonically as the make-up requirement increases. The total evaluated costs for all of the wet/dry systems are significantly higher than that for the wet system, but significantly lower than the dry system.

The results of a comparable economic evaluation for typical wet/dry systems designed for a nominal 1000-MWe nuclear power station are shown in Tables 5.4 and 5.5(14). These data show characteristics similar to those presented in Tables 5.2 and 5.3 for a fossil plant.

5.3.3.2 Plant Performance--

An example of the plant performance of a wet/dry system for a nominal 1000-MWe nuclear power plant is shown in Figure 5.11 for a 10 percent make-up wet/dry tower system operating in the S1 mode(10,19). The performance shown includes the gross and net plant output (gross output-cooling auxiliary power requirement), turbine back pressure, and make-up flow rate over an annual cycle.

When the wet and dry towers are operating together, the turbine back pressure is maintained near its design value of 4.5 in. HgA (114.3 mm HgA), and the gross plant output (MWe) is at its lowest value. The wet tower modules are gradually taken out of service as the ambient temperature decreases. The dry tower takes over completely when it is able to carry the plant heat load while maintaining the turbine back pressure at or below the design value of 4.5 in. HgA. At this point, all the wet towers are out of service, and no water is required as shown by the make-up curve. When the dry tower operates alone and in response to the falling dry bulb temperature, the capacity of the dry tower system increases, resulting in lower back pressure and greater gross and net plant outputs. The gross plant output in Figure 5.11 reflects the back pressure variation as described above.

The comparisons of the gross and net plant outputs for the wet/dry and reference tower systems are shown in Figures 5.12 and 5.13, respectively. The corresponding ambient temperature at which the cooling system and plant performance were determined is shown superimposed on the figures.

The difference in gross plant output (Figure 5.12) between the 1 percent and 10 percent or between the 10 percent and 40 percent make-up wet/dry tower systems at the peak ambient temperature reflects a back pressure difference of 0.5 in. HgA (12.7 mm HgA) and approximately 11 MWe difference in gross plant output. Although the lower fraction make-up systems suffer larger capacity reductions, operations of the larger dry systems result in shorter durations of combined wet and dry tower operation where the maximum capacity deficit occurs.

Integration of the capacity deficit over the annual cycle determines the amount of replacement energy required for the wet/dry and the reference systems. The amount of replacement energy is represented in Figure 5.12 by the area bound between the constant base generator output line and the gross output curve for each cooling system. Thus, the figure also represents the relative magnitude of the replacement energy needed by the wet, wet/dry, and dry systems. It further shows that the higher percentage make-up wet/dry systems require more replacement energy than the lower percentage make-up systems. This is obvious between the 1 and 10 percent systems and also between the 20 and 40 percent systems.

Figure 5.13 shows the influence of pump and fan capacity requirements on the capacity deficits relative to the base plant output.

5.3.3.3 Water Usage and Costs--

One of the criteria used in the design of an optimum wet/dry tower is the annual make-up requirement. The annual make-up is the summation of the water usage during each increment of an ambient temperature cycle. Since most streams generally have a low stream flow in summer or fall when the cooling tower make-up requirements are the highest, it is important to determine the water usage requirements on a monthly or a daily basis during the annual cycle.

Figure 5.14 shows the total amount of make-up required for each month during a typical annual cycle for cooling systems designed to serve a nuclear power plant at San Juan, N. M. Figure 5.15 shows the maximum make-up flow rate during each month. Although the annual percentage make-up is small, the maximum flow rate can be large. For example, even for the one percent make-up system, the maximum make-up flow rate is almost one-third of that required by the wet system, because the system requires about a third of the wet cells needed for the wet tower. The total monthly requirement, however, is less than 10 percent of the wet system requirement. The information given in Figures 5.14 and 5.15 can be used to determine whether stream flow conditions match the make-up requirements, or to size the reservoir or impoundment necessary for station operation. Figures 5.16 and 5.17 show make-up requirements for a comparably sized fossil power plant at the same location.

The water penalty is of special significance when making cost comparisons of wet and wet/dry cooling system alternatives. The water penalty costs are listed as separate items in Tables 5.3 and 5.5, (San Juan fossil and Sundesert nuclear, respectively). Excluding these costs from the total evaluated cost of the cooling system would significantly increase the cost differential between the wet and the wet/dry cooling systems. The water penalty cost includes: 1) the water purchase cost, 2) the capital cost of water treatment facilities, such as clarifiers and water treatment chemicals, 3) the capital and operating cost of water supply which includes make-up (intake structure) pumps, pipelines and associated structures, and 4) the cost of blowdown disposal. The capital cost components of the water supply penalty for these plants includes a 25 percent indirect cost component. The Sundesert water penalty includes the cost of a solar evaporation pond for blowdown, whereas at San Juan blowdown disposal costs were assumed to be negligible.

5.3.4 Economic Feasibility of Wet/Dry Tower Systems for Water Conservation

Studies sponsored by ERDA(10), EPA(11) and the California State Energy Commission(14), from which the data on wet/dry systems for water conservation have been cited, have concluded:

1. Wet/dry cooling systems can be designed to provide a significant economic advantage over dry cooling yet closely match the dry tower's ability to conserve water. A wet/dry system which saves as much as 99 percent of the make-up required by a wet tower can maintain that economic advantage. Therefore, for power plant sites where water is in short supply, wet/dry cooling is the economic choice over dry cooling. Even where water supply is remote from the plant site, this advantage holds.

2. Where water is available, wet cooling will continue to be the economic choice in most circumstances. Only if resource limitation or environmental criteria make water costs excessive can wet/dry cooling become economically on par with wet cooling.

3. The economic advantage of wet/dry cooling over dry cooling reduces the need for further development of high back pressure turbines for nuclear power plant applications.

4. The dry surface areas needed for wet/dry options are, in general, less than that required for the dry cooling systems using the high back pressure turbines, but remain large in size. Therefore, the development of improved dry surfaces should be continued for use in wet/dry cooling.

TABLE 5.1. TYPICAL SIZE, PERFORMANCE AND COSTS OF HYBRID WET/DRY TOWER SYSTEMS FOR PLUME ABATEMENT*(11)

Ground fogging (hr)	5				10	20	30	60
Dry Section Height (ft)	0	5 ft	10 ft	15 ft	0	0	0	0
Number of Wet/Dry Tower Modules	43	35	31	29	41	37	33	26
Total Capital Cost $\$10^6$	56.41	54.74	54.08	53.92	55.59	51.84	50.25	44.82
Total Penalty Cost $\$10^6$	23.77	24.15	24.30	25.35	23.06	24.40	22.85	25.70
Total Evaluated Cost $\$10^6$	80.18	79.89	78.38	79.27	78.65	76.24	73.10	70.52

*Power Plant: 1000-MWe Fossil
Site: Seattle, Washington
Cost Year: 1985

TABLE 5.2. DESIGN DATA OF TYPICAL WET/DRY COOLING TOWER SYSTEMS FOR A FOSSIL PLANT(11)

SITE: SAN JUAN, NEW MEXICO BASE OUTPUT: 1039 MWe WET/DRY TYPE: MECHANICAL SERIES (S1)

Item	Mech. Dry (H)*	Mech. Dry (L)†	Percentage Make-up Requirement Mechanical Series Wet/Dry					Mech. Wet
			2	10	20	30	40	
Number of Tower Cells, Wet Tower/Dry Tower	0/112	0/274	7/161	11/117	13/98	15/84	17/70	21/0
Maximum Operating Back Pressure P_{max}, in. HgA (mm HgA)	12.60 (320.0)	5.03 (127.8)	5.0 (127.0)	4.5 (114.3)	4.0 (101.6)	3.5 (88.9)	3.5 (88.9)	3.12 (79.2)
Gross Plant Output at P_{max}, MWe	920.4	989.0	989.5	999.1	1009.5	1019.1	1019.1	1025.6
Heat Load at P_{max}, 10^9 Btu/hr (10^{12} J/hr)	4.86 (5.13)	4.62 (4.87)	4.62 (4.87)	4.59 (4.84)	4.55 (4.80)	4.52 (4.77)	4.52 (4.77)	4.50 (4.75)
Heat Load Distribution at P_{max}, (Wet Tower/Dry Tower), %	0.0/100.0	0.0/100.0	38.7/61.3	60.9/39.1	73.2/26.8	82.2/17.8	85.0/15.0	100.0/0.0
Annual Make-up Water for Wet Towers, 10^8 gal (10^6 m^3)	0.0 (0.0)	0.0 (0.0)	0.625 (0.237)	2.90 (1.10)	5.97 (2.26)	8.85 (3.35)	11.90 (4.50)	29.53 (11.18)

* H-High Back Pressure Turbine

† L-Conventional Low Back Pressure Turbine

TABLE 5.3. COST COMPONENTS ($$10^6$) OF TYPICAL WET/DRY COOLING SYSTEMS FOR A FOSSIL PLANT(11)

SITE: SAN JUAN, NEW MEXICO YEAR: 1985 WET/DRY TYPE: MECHANICAL SERIES (S1)

	Mech. Dry (H)*	Mech. Dry (L)+	Percentage Make-up Requirement# Mechanical Series Wet/Dry					Mech. Wet
			2%	10%	20%	30%	40%	
Capital Cost:								
Cooling Tower	39.07	95.58	60.20	47.27	41.84	38.11	34.43	12.39
Condenser	11.26	14.46	12.07	10.81	10.12	10.14	9.66	10.13
Circulating Water System	7.86	12.51	11.70	10.26	9.16	9.40	8.82	6.50
Electric Equipment	5.36	12.45	9.81	7.60	6.62	6.01	5.29	1.52
Indirect Cost	15.88	33.75	23.45	18.98	16.92	15.91	14.55	7.63
Total Capital Cost of Base Cooling System**	79.43	168.75	117.23	94.92	84.66	79.57	72.75	38.17
Penalty Cost:								
Capacity Loss	57.54	24.27	24.01	19.37	14.30	9.64	9.64	6.48
Power for Tower & Circulating Water Pumps	11.16	23.37	15.18	12.17	11.22	10.99	9.82	5.12
Replacement Energy	29.62	0.49	4.48	8.04	8.54	7.00	7.98	2.23
Fan Energy & Circulating Water Pumping Energy	9.23	17.45	12.19	9.52	8.62	8.51	7.82	4.23
Cooling System Maintenance	3.91	8.15	5.64	4.71	4.19	4.04	3.75	1.81
Total Penalty Cost of Base Cooling System**	111.46	73.73	61.50	53.81	46.88	40.18	39.01	19.87
Make-up Water Penalty Cost:								
Make-up Water Purchase & Treatment Cost	0.00	0.00	0.10	0.48	1.00	1.47	1.98	4.92
Capital Cost of Make-up Water Supply Facilities	0.00	0.00	5.50	7.00	7.76	8.32	8.59	9.46
Power and Energy Cost for Pumping Make-up Water	0.00	0.00	0.18	0.30	0.38	0.45	0.50	0.74
Total Make-up Water Penalty Cost	0.00	0.00	5.78	7.78	9.14	10.24	11.07	15.12
Total Evaluated Cost of the Complete Cooling System	190.89	242.48	184.51	156.51	140.68	130.00	122.83	73.16

* H - High Back Pressure Turbine

+ L - Low Back Pressure Turbine

** Base Cooling System - Cooling system without make-up and water treatment facilities

# Percentage of annual make-up required by optimized wet tower

TABLE 5.4. DEISGN DATA OF TYPICAL WET/DRY TOWER SYSTEMS FOR A NUCLEAR POWER PLANT(14)

SITE: Blythe, Calif. MAKE-UP INTAKE SITE: OTO BASE OUTPUT: 1023.10 MWe at 2.5 HgA

Tower System	Wet/Dry					Wet
Annual Make-up Quantity	5%	10%	20%	30%	40%	100%
Number of Tower Cells, Wet Tower/Dry Tower	13/221	17/203	21/178	25/145	28/115	43
Surface Area of Tower, Acres	9.90	9.43	8.63	7.50	6.44	2.60
Maximum Operating Back Pressure P_{max}, in. HgA	5.00	4.50	4.00	4.00	4.00	3.17
Gross Plant Output at P_{max}, MWe	962.8	975.3	988.2	988.2	988.2	1009.2
Heat Load at P_{max}, 10^9 Btu/hr*	6.65	6.60	6.56	6.56	6.56	6.49
Heat Load Distribution at P_{max}, (Wet Tower/Dry Tower), %	51.3/48.7	63.3/36.7	75.4/24.6	79.4/20.6	82.8/17.2	100.0/0.0
Annual Make-up Water for Wet Towers, 10^3 acre-feet	0.76	1.55	2.77	4.19	5.78	14.18

* A constant auxiliary heat load of 2.16×10^8 Btu/hr must be added to each indicated value.

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TABLE 5.5. COST COMPONENTS ($$10^6$) OF TYPICAL WET/DRY COOLING SYSTEMS FOR A 1000-MWe NUCLEAR PLANT(14)

SITE: Blythe, Calif. MAKE-UP INTAKE SITE: OTO YEAR: 1985

Tower System	Wet/Dry					Wet
Annual Make-up Quantity	5%	10%	20%	30%	40%	100%
Capital Cost:						
Cooling Tower	84.611	80.295	73.458	63.820	54.732	21.688
Condenser	20.135	19.094	19.094	17.021	16.227	19.088
Circulating Water System*	23.374	22.070	22.969	15.712	14.437	14.975
Electric Equipment	13.854	13.142	12.160	9.980	8.498	3.004
Indirect Cost	35.493	33.651	31.920	26.633	23.474	14.689
Total Capital Cost of Heat Rejection System	177.467	168.252	159.601	133.166	117.368	73.444
Penalty Cost:						
Capacity Loss	60.290	47.790	34.890	34.890	34.890	13.906
Power for Tower Fans and Circulating Water Pumps	43.657	42.403	41.864	35.217	31.199	19.126
Replacement Energy	21.849	21.741	18.738	25.097	25.754	-3.018
Fan Energy & Circulating Water Pumping Energy	30.225	28.559	27.859	24.081	21.836	13.616
Cooling System Maintenance	12.564	12.240	12.287	10.237	9.479	6.488
Total Penalty Cost of Heat Rejection System	168.585	152.733	135.638	129.522	123.158	50.118
Water Penalty:						
Make-up Water Purchase Cost	0.323	0.655	1.172	1.773	2.447	6.000
Make-up Water Treatment Cost (Capital & Operation)	10.202	13.449	17.986	22.565	27.662	53.873
Make-up Water Supply Cost (Facility, Pumping Power & Energy)	8.061	8.622	9.481	9.675	11.367	12.588
Blowdown Cost (Solar Evaporation Pond)	0.926	1.858	3.340	4.991	8.526	16.487
Total Water Penalty Cost	19.512	24.584	31.979	39.004	50.002	88.948
Total Evaluated Cost of the Complete Cooling System	365.564	345.569	327.219	301.692	290.528	212.510

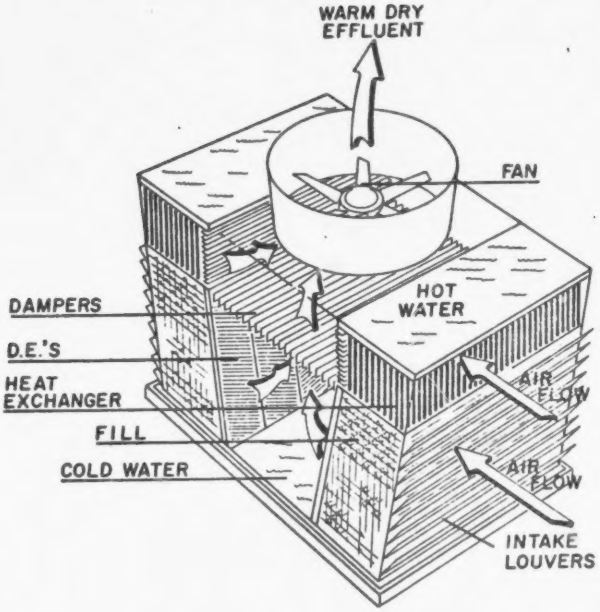
WARM DRY EFFLUENT
FAN
HOT WATER
DAMPERS
D.E.'S
HEAT EXCHANGER
FILL
COLD WATER
AIR FLOW
AIR FLOW
INTAKE LOUVERS

Figure 5.1. Schematic of hybrid wet/dry tower for plume abatement with film-type dry section(2).

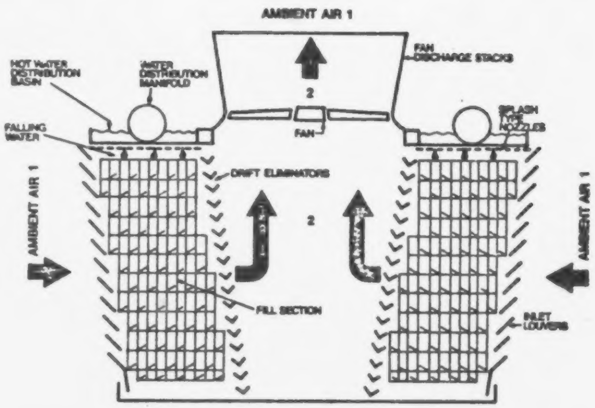
AMBIENT AIR 1
HOT WATER DISTRIBUTION BASIN
WATER DISTRIBUTION MANIFOLD
2
FAN DISCHARGE STACKS
FALLING WATER
FAN
SPLASH TYPE NOZZLES
DRIFT ELIMINATORS
AMBIENT AIR 1
2
AMBIENT AIR 1
FILL SECTION
INLET LOUVERS

Figure 5.2. Conventional mechanical draft wet cooling tower(9).

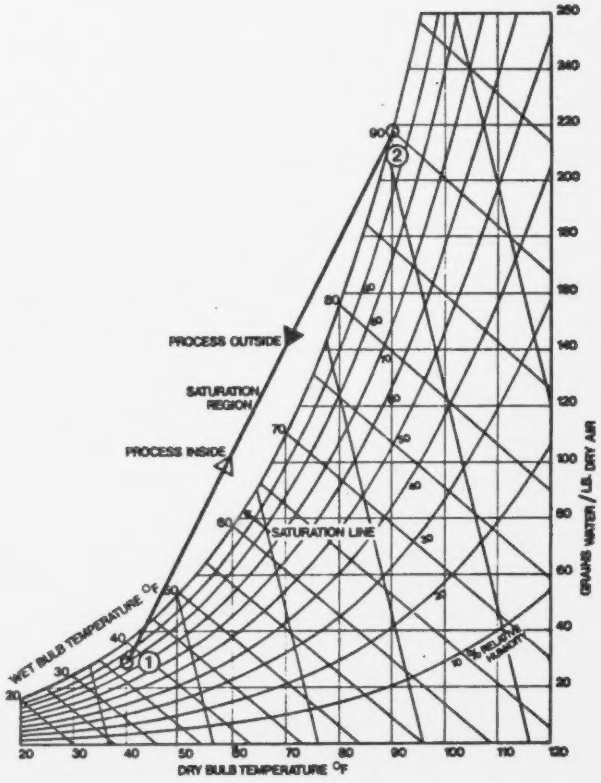

Figure 5.3. Psychrometric process for a mechanical draft wet cooling tower(9).

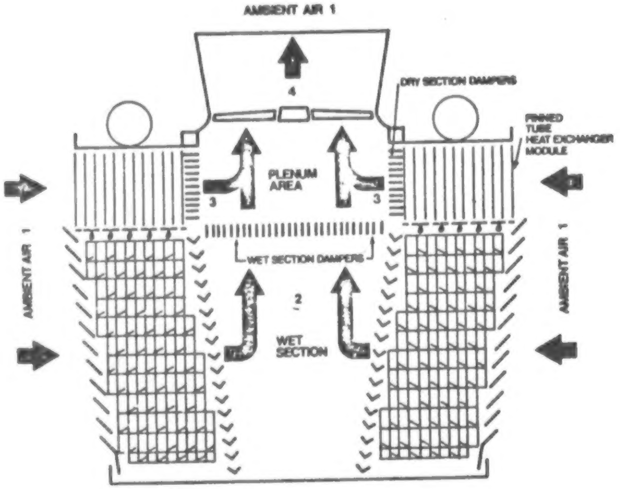
AMBIENT AIR 1
4
DRY SECTION DAMPERS
FINNED TUBE HEAT EXCHANGER MODULE
PLENUM AREA
3
3
WET SECTION DAMPERS
2
WET SECTION
AMBIENT AIR 1
AMBIENT AIR 1

Figure 5.4. Wet/dry mechanical draft cooling tower(9).

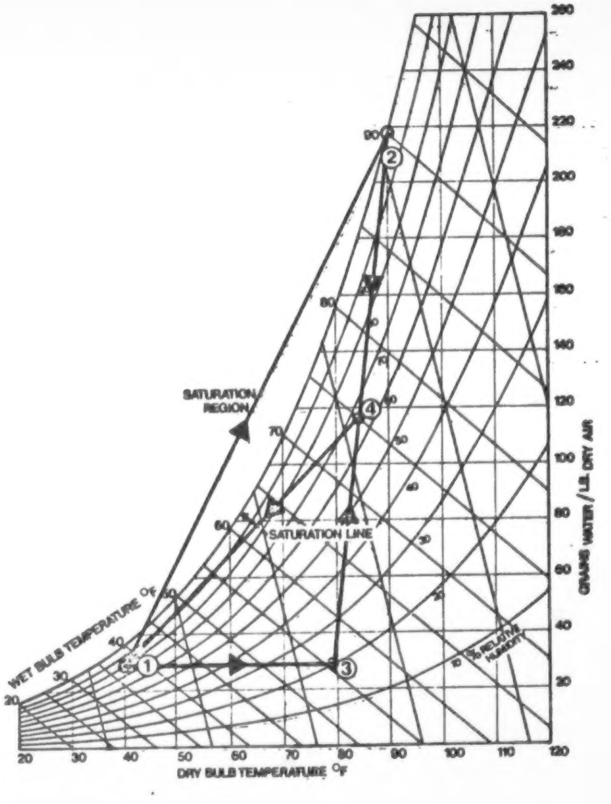

Figure 5.5. Psychrometric process for a mechanical draft wet/dry cooling tower(9).

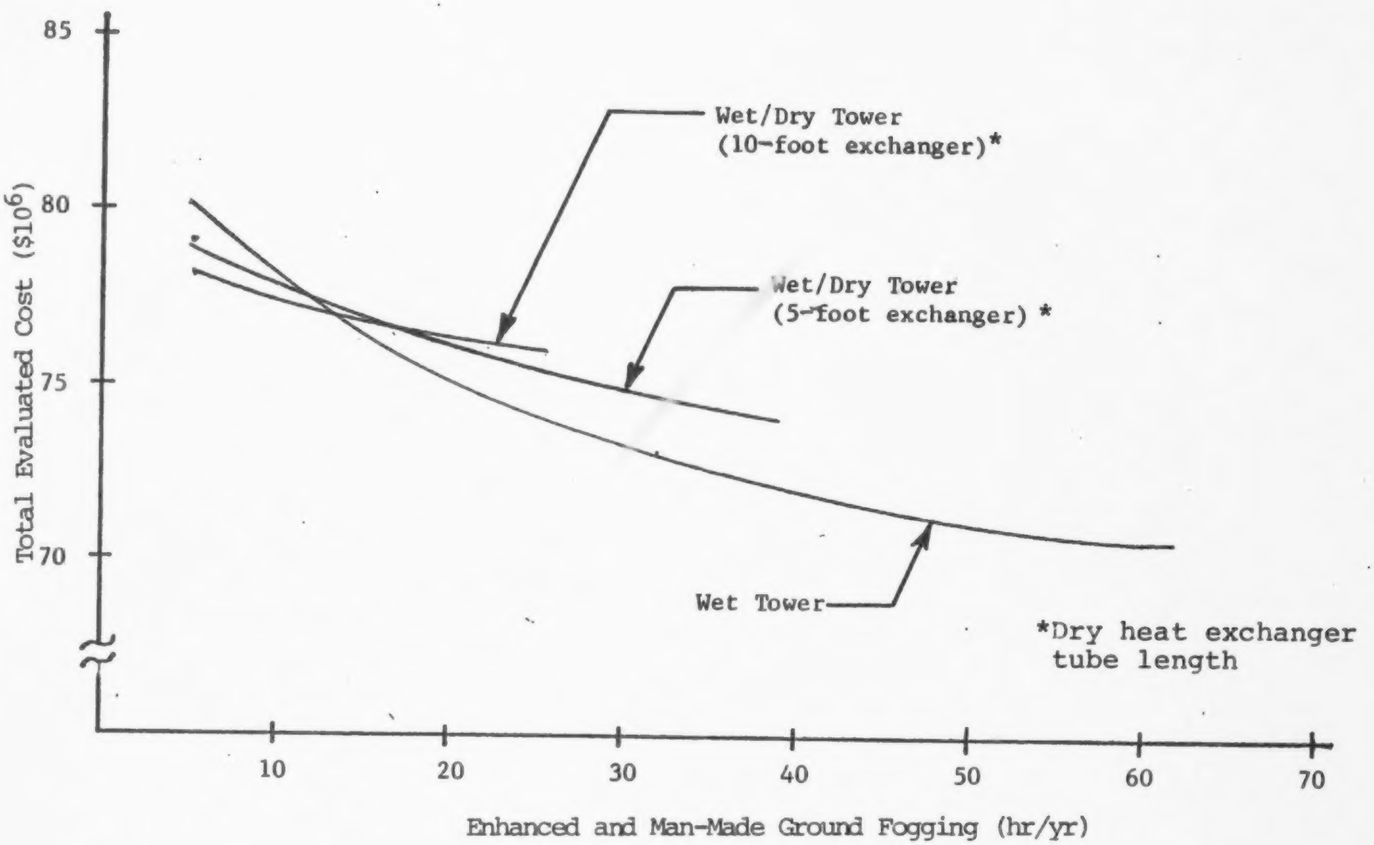

Figure 5.6. Total evaluated cost as a function of ground fogging for various wet and wet/dry tower systems (Seattle site, 1985 dollars)(11).

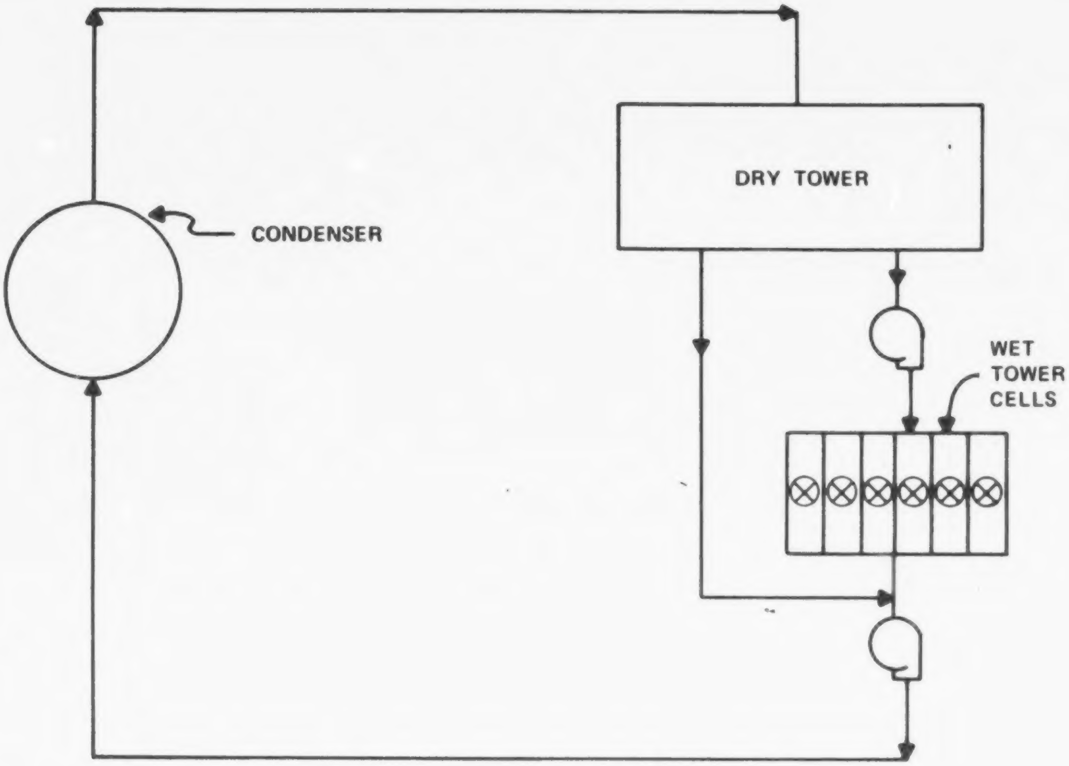
DRY TOWER
CONDENSER
WET
TOWER
CELLS

Figure 5.7. Series water flow wet/dry tower system for water conservation(10).

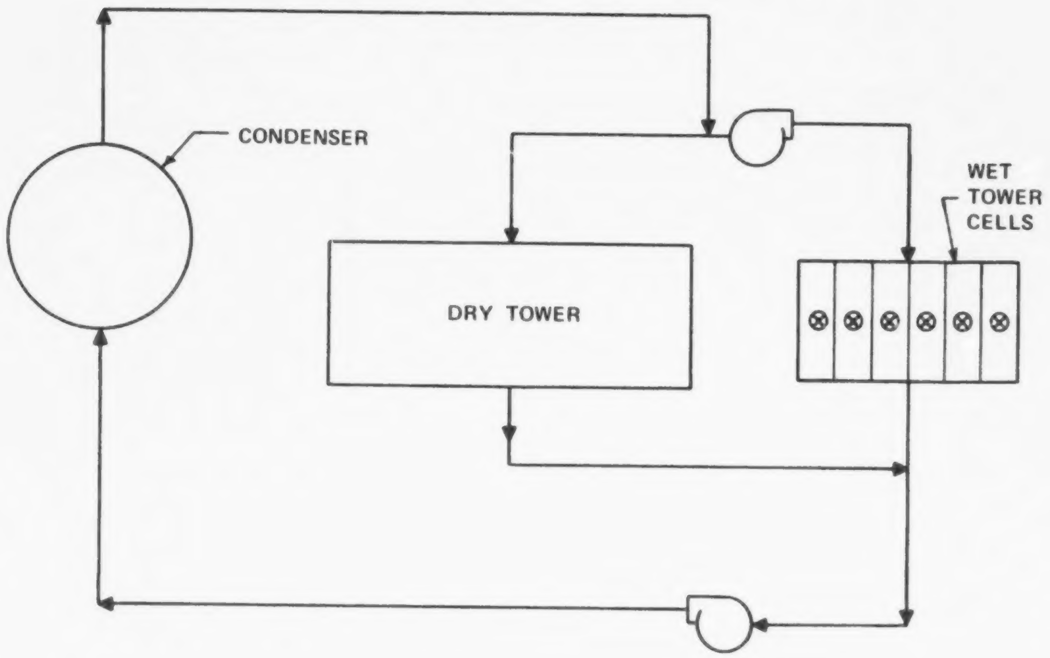
CONDENSER
WET TOWER CELLS
DRY TOWER

Figure 5.8. Parallel water flow wet/dry tower system for water conservation(10).

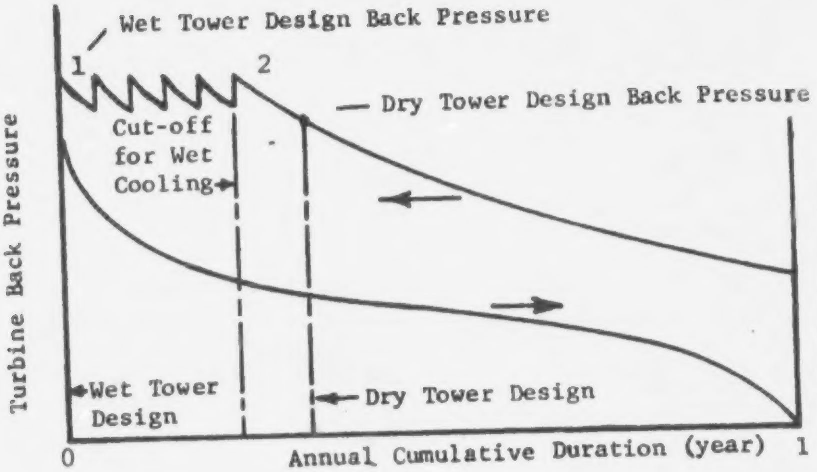

Figure 5.9. Wet/dry tower-mode 1 operation(10,11).

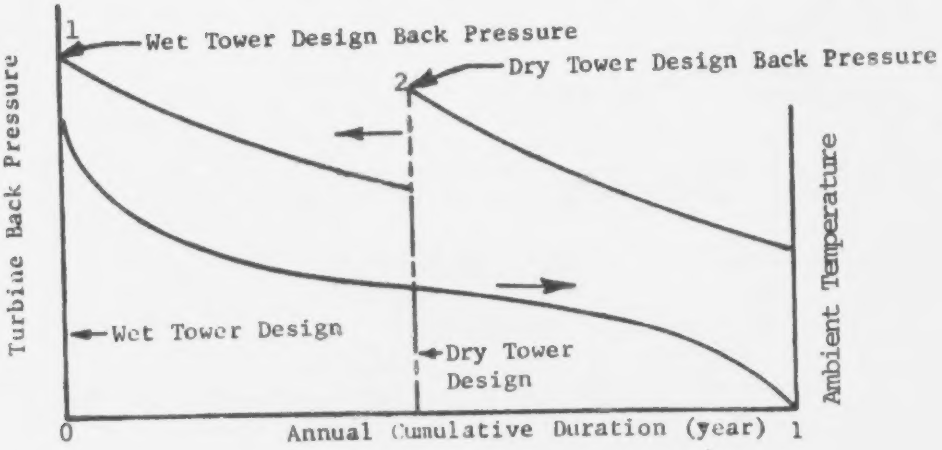

Figure 5.10. Wet/dry tower-mode 2 operation(10,19).

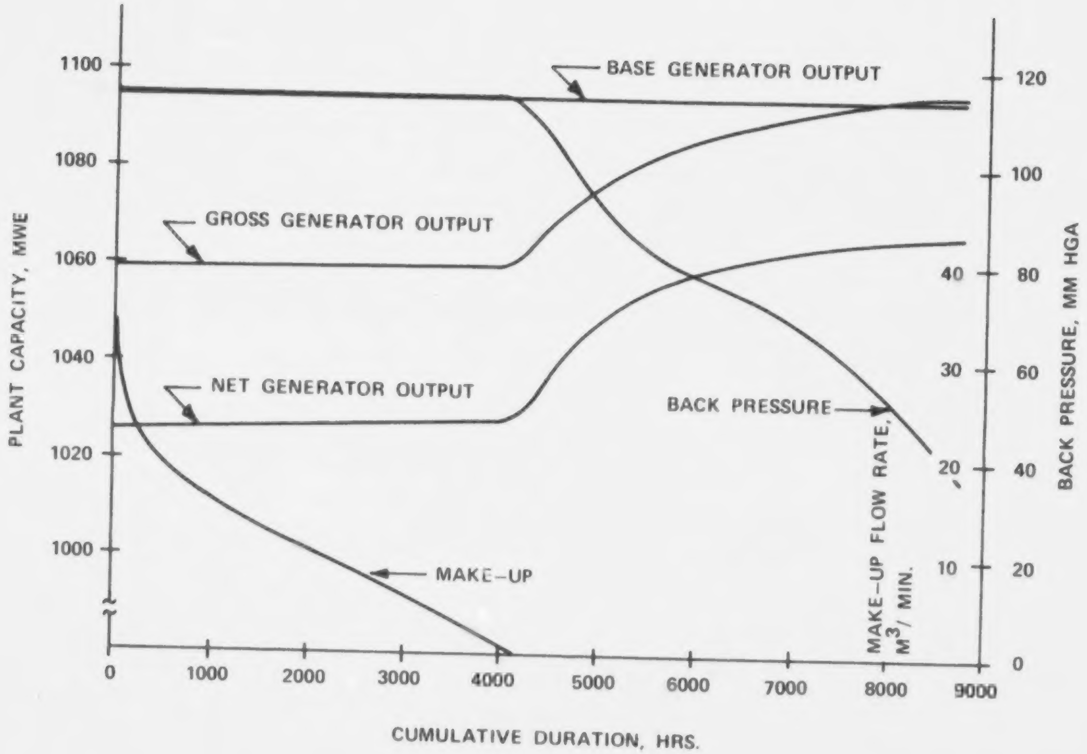

Figure 5.11. Performance curves for a 10% wet/dry cooling system at Middletown site(10,19).

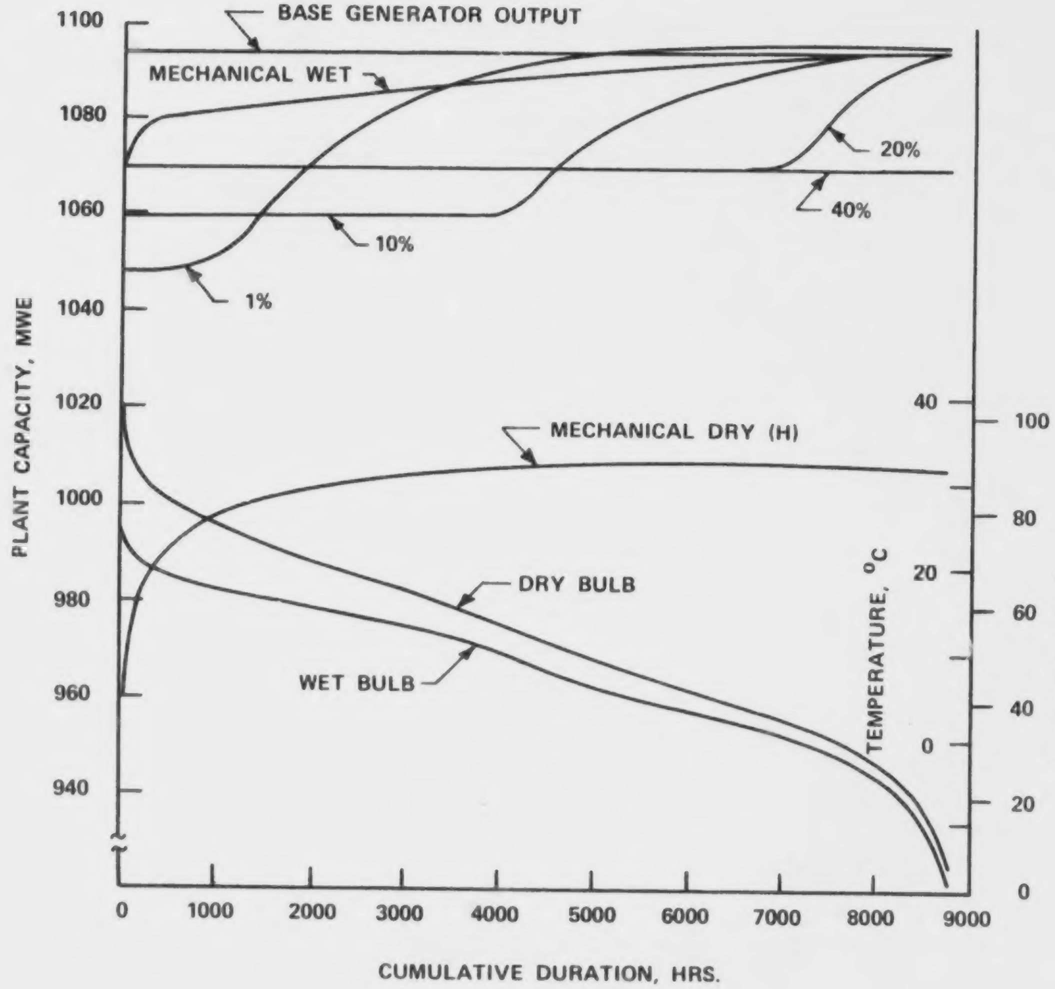

Figure 5.12. Plant performance characteristics (gross output) using wet/dry cooling systems(10,19).

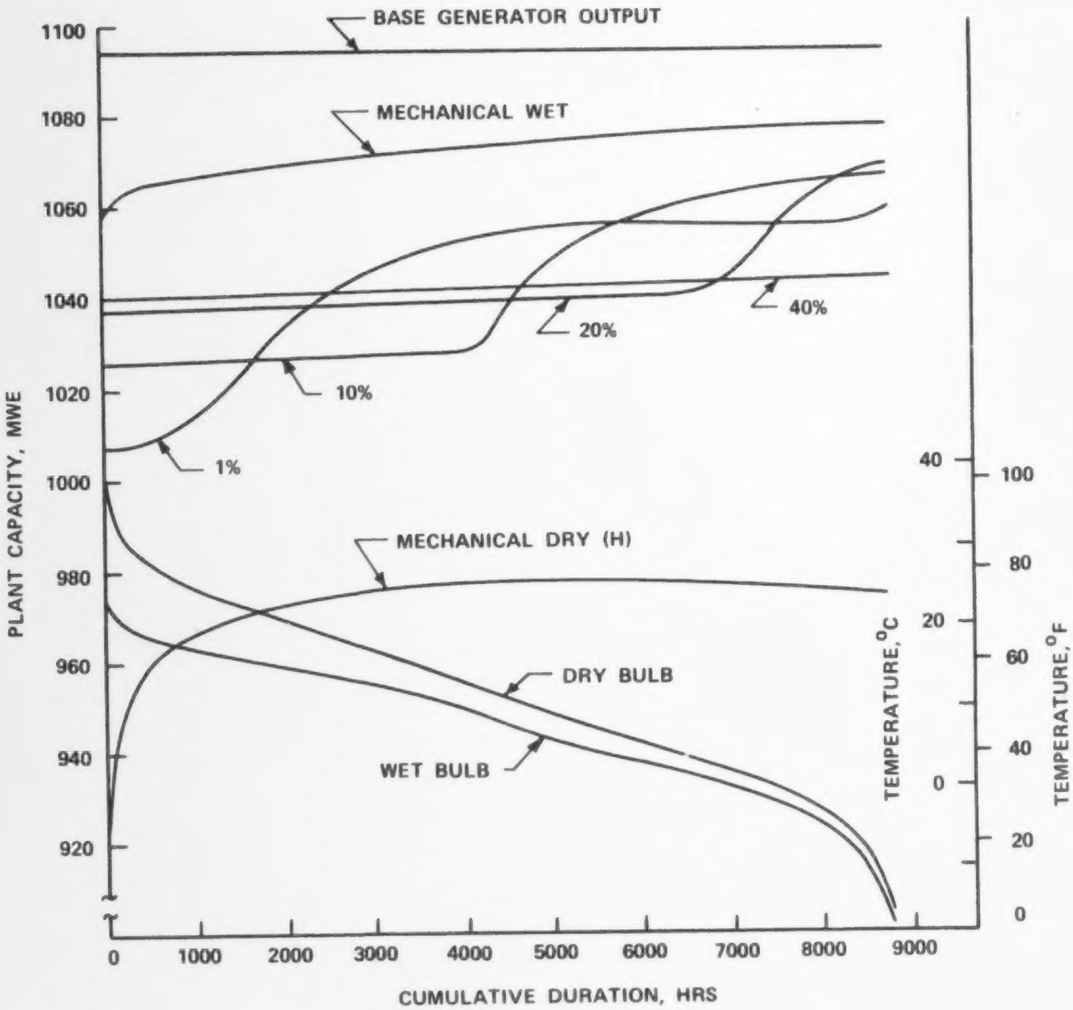

Figure 5.13. Plant performance characteristics (net output) using wet/dry cooling systems(10,19).

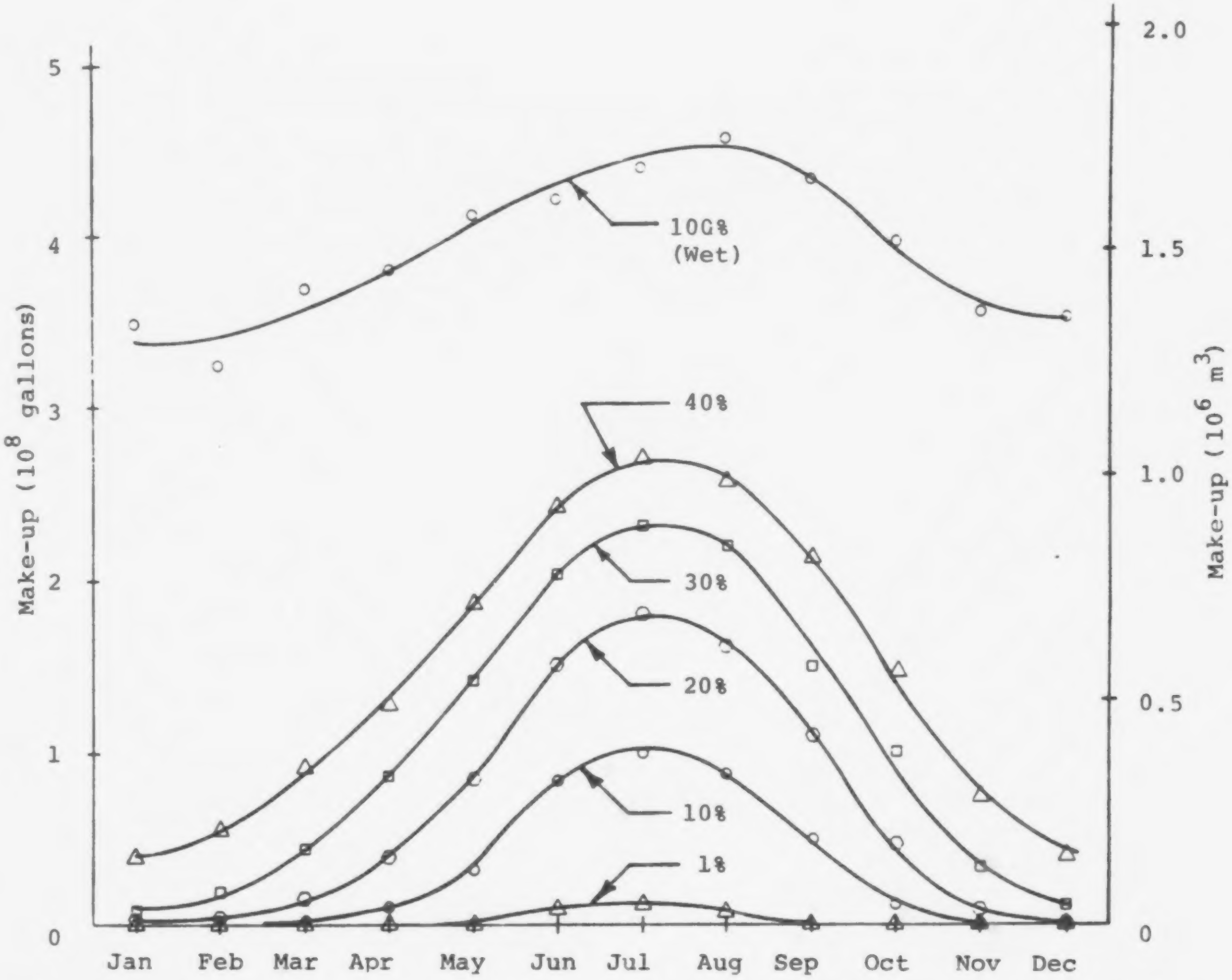

Figure 5.14. Total monthly make-up requirements of wet/dry cooling systems for water conservation: 1000-MWe nuclear plant at San Juan, New Mexico(10).

NOTE: Curves are drawn through the discrete points to facilitate visual observation.

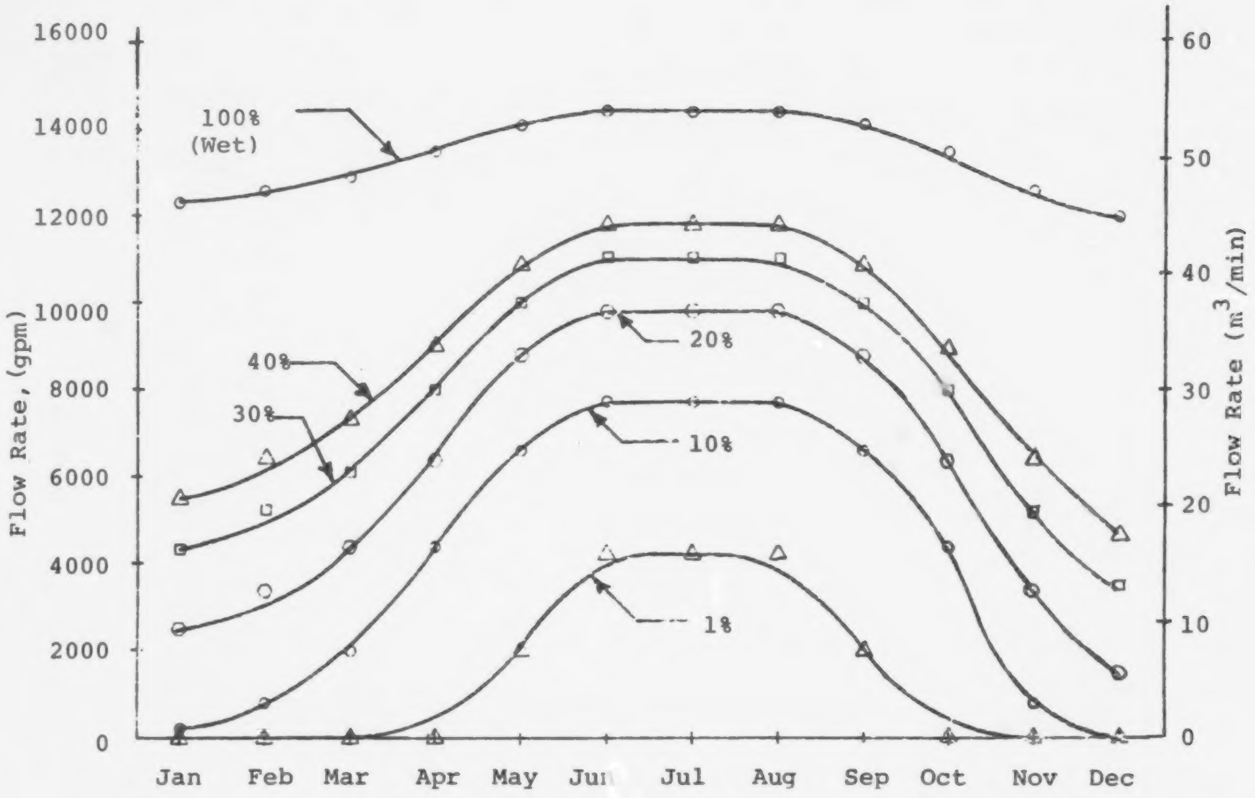

Figure 5.15. Maximum monthly make-up requirements of wet/dry cooling systems for water conservation: 1000-MWe nuclear plant at San Juan, New Mexico(10).

NOTE: Curves are drawn through the discrete points to facilitate visual observation.

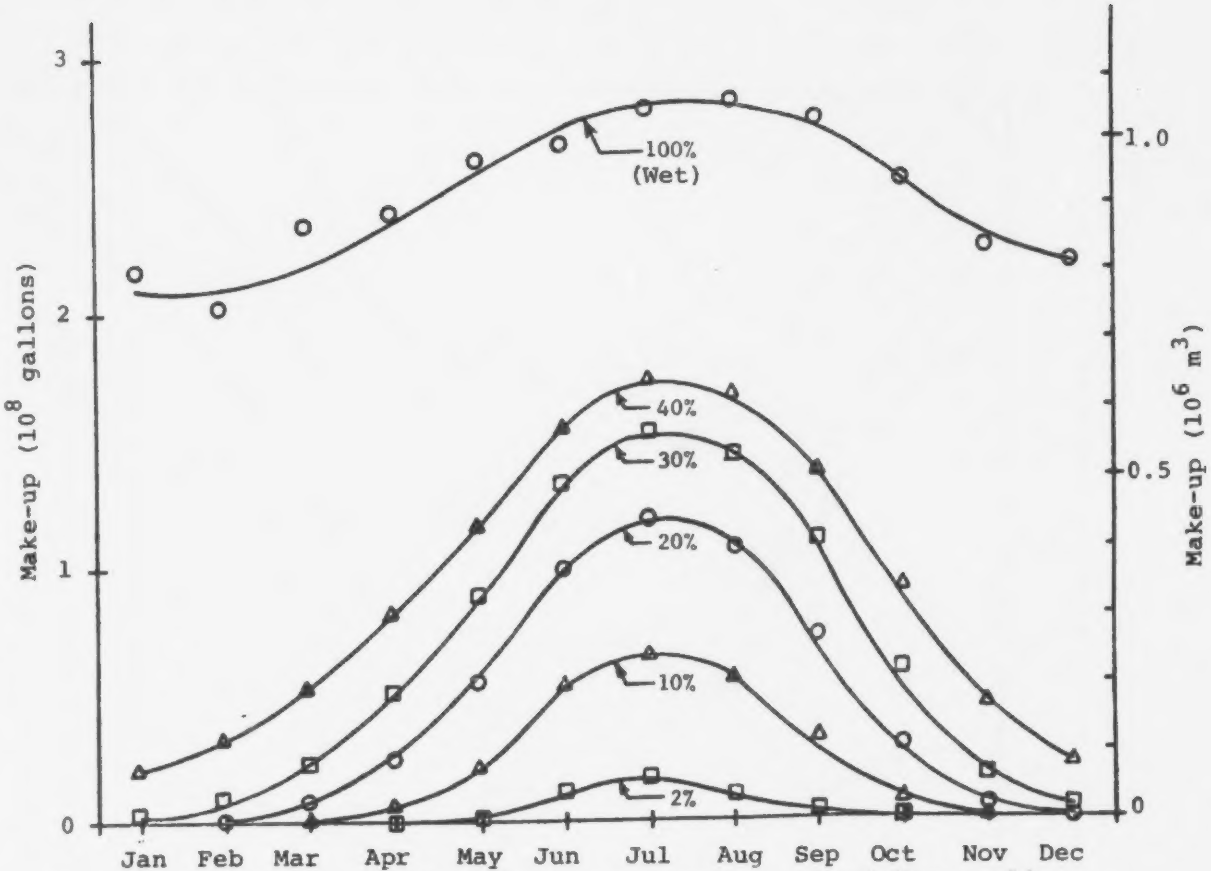

Figure 5.16. Total monthly make-up requirements of wet/dry cooling systems for water conservation: 1000-MWe fossil plant at San Juan, New Mexico(11).

NOTE: Curves are drawn through the discrete points to facilitate visual observation.

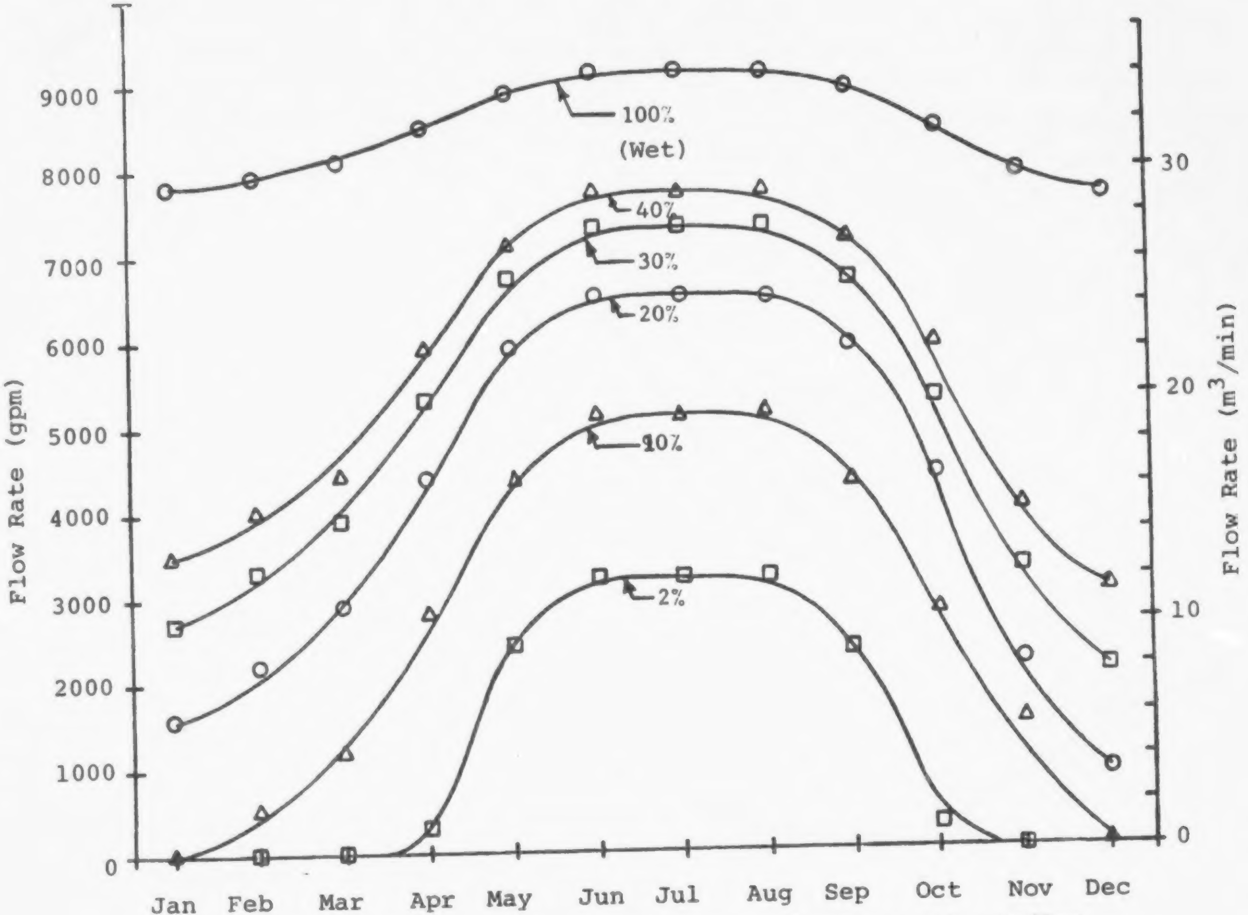

Figure 5.17: Maximum monthly make-up requirements of wet/dry cooling systems for water conservation: 1000-MWe nuclear plant at San Juan, New Mexico(10).

NOTE: Curves are drawn through the discrete points to facilitate visual observation.

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SECTION 6

ADVANCED COOLING SYSTEMS

6.1 INTRODUCTION

Although the present state of knowledge indicates that dry cooling systems have the smallest environmental impact of all the conventional cooling systems, the high cost of electricity from dry cooled generating plants has deterred the wide acceptance of dry cooling by power utilities. Considerable effort has been directed towards reducing these costs. The near-term approach through the use of wet/dry cooling has been described in Section 5. Approaches using advanced concepts which are receiving the most attention are briefly described in the following subsections. The advanced cooling systems are defined as those systems which utilize either evolutionary or revolutionary design approaches, but have not yet been applied to power plants for commercial use. These include the following systems, all of which are evolutionary: 1) ammonia dry cooling systems, 2) Curtiss-Wright integral-fin dry cooling systems, 3) fluidized bed dry cooling systems, 4) rotary (periodic) heat exchanger dry cooling systems, 5) deluge wet/dry cooling systems, and 6) MIT wet/dry cooling systems. The first four are all-dry systems; the last two are advanced wet/dry systems.

6.2 AMMONIA DRY COOLING SYSTEM

6.2.1 System Description and Principle of Operation

The ammonia dry tower system is a dry cooling system which utilizes ammonia as an intermediate cooling fluid which undergoes a phase change during the cooling process(1-5). This dry cooling system is physically an indirect system. It is, however, functionally similar in many respects to the direct system where exhaust steam is ducted directly to an air-cooled condenser.

Figure 6.1 is the process flow diagram. Exhaust steam from the last stage of the turbine is condensed in the condenser/reboiler located directly below the turbine. Instead of water circulating through the tubes, liquid ammonia is boiled as it is pumped through the tubes under pressure set by the operating temperature in the condenser. The ammonia quality emerging from the tube varies from 50 percent to 90 percent. This two-phase mixture is passed through a vapor-liquid separator from which the vapor is sent to the air-cooled heat exchangers and condensed while the liquid is combined with the ammonia condensate from dry heat exchangers and recycled back through the condenser/reboiler.

The ammonia vapor from the vapor-liquid separator flows to the dry tower under the driving force of the vapor pressure difference between the condenser/reboiler and the dry towers. In the dry tower, the ammonia vapor is condensed. The condensed ammonia is pumped back to the condenser/reboiler. Isolation valves at the inlet and outlet manifolds of a tower section provide a means of removing sections of the tower from service as may be required for maintenance or reduced cooling capability.

6.2.2 Advantages and Disadvantages of the Ammonia Dry Cooling System (1-5)

The significant advantages of the ammonia system include the following:

1. Isothermal condensation occurs in the dry tower; consequently, a larger temperature differential for heat transfer occurs in an ammonia system than that in an indirect air-water system, so that less dry heat exchanger surface area is required.

2. The much lower volumetric flow rate and specific volume of the ammonia vapor results in smaller transfer lines between the plant and the tower than would be required for steam in a direct dry system.

3. No problems with freezing occur in the dry tower and, consequently, there is no requirement for louvers, drain valves or other low temperature safety systems.

4. No pumping is required to move ammonia vapor to the dry tower, and very little pumping is required to pump the liquid ammonia back to the condenser/reboiler.

The major disadvantages are as follows:

1. The higher operating pressure of the ammonia system requires the use of heavier and more costly piping.

2. Since the condensation of steam and boiling of ammonia in the condenser/reboiler are both isothermal processes, the fixed temperature difference provides a temperature potential (i.e., the log mean temperature difference) that is lower than that which is available in the condenser of a conventional dry system. Thus, for the same overall heat transfer coefficient, more surface is required for the condenser/reboiler.

3. Ammonia vapor is toxic and somewhat flamable.*

4. There is considerable uncertainty in the operational characteristics and licensing requirements of the large ammonia systems needed for power plant use.

6.2.3 Current Development Status of the Ammonia Concept

The ammonia dry cooling system is currently being developed at Battelle-Pacific Northwest Laboratories under the sponsorship of the Department of Energy (DOE) and the Electric Power Research Institute (EPRI). Also actively engaged in the development of this system is the Linde Division of the Union Carbide Corporation under the sponsorship of EPRI. Cost studies performed by Union Carbide for EPRI indicate a substantial reduction in total cooling system cost for the ammonia concept as compared with an optimized dry cooling system of conventional design(5). These results are confirmed, by and large, by an independent study performed by Battelle-Pacific Northwest for ERDA (DOE). The use of improved heat transfer surfaces, such as that developed by Curtiss-Wright and presently under study by Union Carbide, can be used to further optimize the system.

It appears that the final system design proposed for testing in an experimental facility may use both deluge wet cooling and advanced heat transfer surfaces. Work is presently being performed by both Battelle-Pacific Northwest and Union Carbide toward the development of the design of a demonstration dry cooling system of this type.

6.3 CURTISS-WRIGHT DRY COOLING SYSTEM

The advanced aspect of the dry tower developed by the Curtiss-Wright Corporation lies in the high performance and low cost heat transfer surface of this unique fin-tube geometry(6,7). The Curtiss-Wright dry tower otherwise would operate exactly as the conventional fin-tube dry tower.

*Author comment-explosive in 16 to 25 percent air mixture.

6.3.1 Description of Curtiss-Wright Integral-Fin Tubes

The Curtiss-Wright fin-tubes are called integral-fin tubes. These fin-tubes are fabricated by a special manufacturing process; namely by machining the fins from the surface of a preformed extrusion. This patented process is accomplished on a modified, high-speed punch press by essentially lifting a chip from the tube surface to form the fin without creating any scrap material. This process is applicable for forming integral fins on round tubes, single-port, and multi-port flat tubes. Figure 6.2 shows a typical multi-port integral-fin flat tube.

Test results(6) have demonstrated superior performance compared to conventional round, fin-tube geometries. The contributing factors include the following:

1. The integral-fin concept eliminates bonding resistance to heat transfer.
2. The fin interruptions inhibit fin boundary layer buildup and increase localized air turbulence, resulting in improved heat transfer performance compared to continuous fins.
3. The fin and tube geometry can be varied over a wide range to optimize performance for specific requirements.

Since the integral-fin tubes are fabricated from a preformed extrusion, the fin and tube geometries can have wide variation and are limited in size only by the capacity of extrusion. Current development is centered in the multi-port flat tubes (Figure 6.2) using aluminum.

6.3.2 Development Status of the Curtiss-Wright Dry Tower System

The Curtiss-Wright integral-fin heat exchangers have been successfully used in large industrial applications. For power plant applications, it has been under active development by the Curtiss-Wright Corporation with partial sponsorship from the U. S. Department of Energy (DOE). These studies have shown a substantial savings in capital and operating cost relative to the conventional round finned-tube dry tower systems(6).

6.4 FLUIDIZED BED DRY COOLING SYSTEMS

6.4.1 General Description

The fluidized bed heat exchanger consists of a shallow bed of small particles which are caused to float or fluidize by forced air passing through the bed(8). A fluid bed system patented by Seth(9) is shown in Figure 6.3. Uniformly spaced tubes containing heated water from the plant are placed horizontally in the fluidized bed. Heat is transferred from the hot fluid through the tube walls into the fluidized bed where the air is sensibly heated before being exhausted to the atmosphere. The fluidized bed permits higher transfer of heat than that of a standard design where air is passed over finned tubes. Heat transfer augmentation is realized mainly by the destruction or reduction of the boundary layer around the tubes through the presence of particles; thus the rate of heat conduction is increased(8,9).

The most significant attraction of the fluidized bed heat exchanger is its high overall heat transfer coefficient, due to the presence of the fluidized bed. If this enhanced coefficient sufficiently reduces the cost of heat rejection without creating significant technical problems, the fluidized bed concept should be seriously considered as an alternative to standard dry cooling techniques and conventional wet cooling methods.

Several variations on the fluidized bed heat exchanger are being considered for application to dry cooling heat rejection. Both finned and smooth tubes can be used in the bed. Also, the fluidized bed can be operated partially wet to dissipate heat both by sensible heating of the air and evaporation of water(8).

Current results indicate that two factors are important to the success of the fluidized bed heat exchanger. The first is the design of a system which yields a high overall heat transfer coefficient. The second is the reduction of fan power requirements for the air. Optimization of these two factors may provide a promising heat rejection system which is technically feasible and economically competitive to conventional dry cooling systems.

6.4.2 Development Status

Although bench testing of this concept has been performed at the Massachusetts Institute of Technology (MIT), there is no industrial development of this concept at the present time.

6.5 ROTARY (PERIODIC) HEAT EXCHANGER DRY COOLING SYSTEM

6.5.1 System Description and Principle of Operation(10)

Conceptually, the periodic cooling tower represents a compromise between the dry cooling tower and the wet cooling tower. Figure 6.4 shows the proposed design for the periodic exchanger. A tower consists of a number of rotary heat exchangers as shown in Figure 6.5. The heat transfer surface is made of a number of coaxial parallel discs which rotate from the hot water to the cooling air flowing parallel to the disc surfaces.

As the heat exchanger rotates, the surfaces of the discs are heated by the hot water and then cooled by the air stream, thus continually transferring heat from the hot to the cold stream. A thin layer of oil is kept on the water surface so that the discs are coated by the oil as they leave the water. Thus, there is little direct air-water interface and little evaporation. Tests on a scale model have shown that an oil film can suppress evaporation to less than 0.4 percent. Under either condition, the oil can be removed and the discs operated as an evaporative tower.

6.5.2 Advantages and Disadvantages of Periodic Cooling Tower Concept

The potential advantages of the periodic cooling tower include the low cost of the discs and the ability of the tower to operate wet or dry. A periodic tower could be significantly less expensive than a conventional dry tower, and with the ability to operate wet, the high capacity losses incurred by conventional towers during periods of high ambient temperatures could be minimized.

The potential disadvantages include operational problems for a large number of rotating heat exchanger elements, high power consumption, large number of fans, and potential fouling by and emulsification of the oil film.

6.5.3 Development Status

Although bench-scale testing of this concept has been performed, there has been no industrial development of the periodic cooling tower.

6.6 PLASTIC TUBE DRY COOLING SYSTEM

6.6.1 General Description

The plastic tube heat exchanger has been developed in Italy in conjunction with the development of a low profile natural draft tower. The low profile natural draft arrangement results in low air flow and, consequently, low heat transfer coefficients which, in turn, result in the requirement of very large but inexpensive surfaces. From these considerations emerged a design using fin-less plastic tube heat exchangers(11).

The specific advantage claimed for this new design is the reduced cost of material and labor for construction. As currently envisioned, the heat exchanger would be field-assembled by connecting 50-meter-long sections of plastic tube to metallic tubeplate headers with specially developed plastic spacers and leakproof neoprene rings. The finished product would be an air-cooled heat exchanger module in the shape of a dihedron. Several of these dihedrons would be assembled side-by-side, along with feeding and connecting pipes, and suspended on steel legs inside a rectangular, low profile, natural-draft tower. A proposed design is shown in Figure 6.6.

The hydraulic design of the coils promotes low air-side and water-side pressure drops. The low air-side pressure drop allows the heat exchanger to be used inside a low profile natural-draft cooling tower. The rectangular tower proposed for use with the heat exchanger assembly would be 40 meters high and would be constructed using a modular steel structure supporting an aluminum, galvanized steel or fiberglass skirt.

The dry tower of the plastic heat exchanger design is said to be competitive with the dry tower using conventional heat exchangers, and the dry system is suitable for use with conventional turbines operating at a maximum back pressure of five inches of mercury. The plastic tubes are designed to have a 30-year service life under the most extreme combinations of operating temperature and pressure.

6.6.2 Development Status

A full-scale demonstration dihedron module has been constructed and operated in Italy. After two years of testing, the thermal and hydraulic advantages of the proposed design have been verified, and the durability of the plastic materials has been demonstrated. After operation at maximum temperature, pressure, and exposure to the elements for two years, the external surfaces of the tubes were untarnished and no problems of deterioration or leaks were encountered(12). In this country the plastic fin-less tube dry cooling concept is presently being investigated on a conceptual design basis by the Battelle-Pacific Northwest Laboratories(13).

6.7 DELUGE WET/DRY COOLING SYSTEM

6.7.1 General Description

Deluge cooling is a method of augmenting the capabilities of a dry cooling tower by flushing the dry surfaces with water and utilizing the heat rejection driving force of water evaporation to aid a dry cooling system to handle heat loads at elevated temperatures.

In one method, the delugeate (water) is "sprayed" on a plate-fin dry heat exchanger as shown in Figure 6.7 such that water runs in a thin film down each side of the vertical fin plates oriented transversely to the air flow. The thin delugeate film allows sufficient passages for this air flow to pass between the wetted fins and carries away the evaporated water plus any sensible heat that it picks up by being in close contact with the delugeate warmed by the tubes and fins. The surface is designed so that the film is unbroken; thus, there is no dry surface on which scale or corrosion can build. Figure 6.8 shows the general layout of a proposed system(14).

Another proposed method of deluging applies to finned-tubes which are vertical (or near vertical)(14). The air flow is directed across the tubes which may have extended surfaces (fins, spines, wire, etc.). The fluid is distributed by a header system, individual or manifolded, to the top of each tube where it is ejected or spilled on top of or axially down the perimeter of the heat exchange surface. The fluid flows down the tube surfaces (if smooth), spirals between spiral fins or the extended surfaces, essentially covering the entire surface. The fluid, upon reaching the bottom of the tube, is collected by means of funnels, troughs, tanks, headers, or basins and pumped back to the top of the same exchanger surface or directed to another exchanger.

6.7.2 Development Status

Deluge cooling has been successfully tested in plate-fin towers in the Soviet Union. Tests that were made at the Battelle-Pacific Northwest Laboratories (PNL) showed that water will flow smoothly and neatly down a finned tube, presenting a water surface to the air and completely covering all the fin surface with water.

A program sponsored by the Department of Energy and the Electric Power Research Institute is currently underway at PNL to deluge an ammonia dry system with Heller-Forgo plate-fin tube surfaces. Under this program, a six-MWe demonstration system will be constructed and tested(15).

6.8 MIT WET/DRY TOWER SYSTEM

6.8.1 General Description

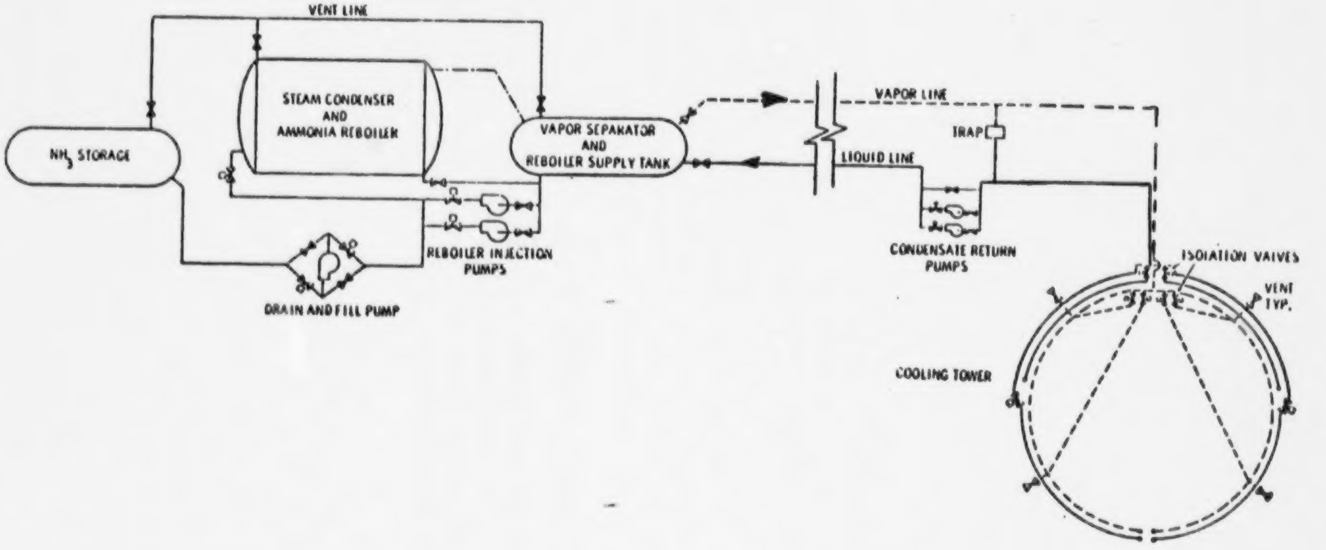
The advanced wet/dry cooling tower design proposed by the Massachusetts Institute of Technology and bench tested is intended for water conservation(16). The tower utilizes a new dry heat transfer surface of sheet metal which is similar in design to a film type wet tower packing. The metal plate has concave channels running down the plate in which hot water flows and the rest of the plate is kept dry as shown in Figure 6.9. As the hot water flows down the channels, it heats the plate which then dissipates heat to the air flowing over both sides of the plate by convection in the dry portion of the surface, while evaporation takes place only at the exposed air-water interface.

The tower packing of the proposed wet/dry tower design is composed of a number of these plates spaced parallel to one another; each plate is separated from the adjacent plates to provide a passage for the air flow. The plates are held at a small angle to the vertical, and water flows down the troughs by gravity after being distributed to the troughs (Figure 6.10). A fan induces air flow between the plates where heat transfer takes place.

The MIT wet/dry towers can be designed to save varying amounts of water relative to a wet tower designed for the same heat load. A design and cost study(17) of this tower concept has indicated a potential cost savings (as compared to the separate wet/dry tower systems discussed in Section 5.3) for the MIT wet/dry tower systems designed to save about 50 percent of water use of a wet tower system. At very high water savings, e.g., 70 percent or higher, the MIT wet/dry tower systems are not competitive with the separate wet/dry tower systems.

6.8.2 Development Status

Although bench demonstration of this concept was performed at MIT under the sponsorship of the U. S. Energy Reserach and Development Administration, there has been no industrial development of this advanced wet/dry tower.



VENT LINE
NH$_3$ STORAGE
STEAM CONDENSER AND AMMONIA REBOILER
VAPOR SEPARATOR AND REBOILER SUPPLY TANK
REBOILER INJECTION PUMPS
DRAIN AND FILL PUMP
VAPOR LINE
LIQUID LINE
TRAP
CONDENSATE RETURN PUMPS
ISOLATION VALVES
VENT TYP.
COOLING TOWER

Figure 6.1. Process flow diagram for a proposed ammonia dry tower system(2).

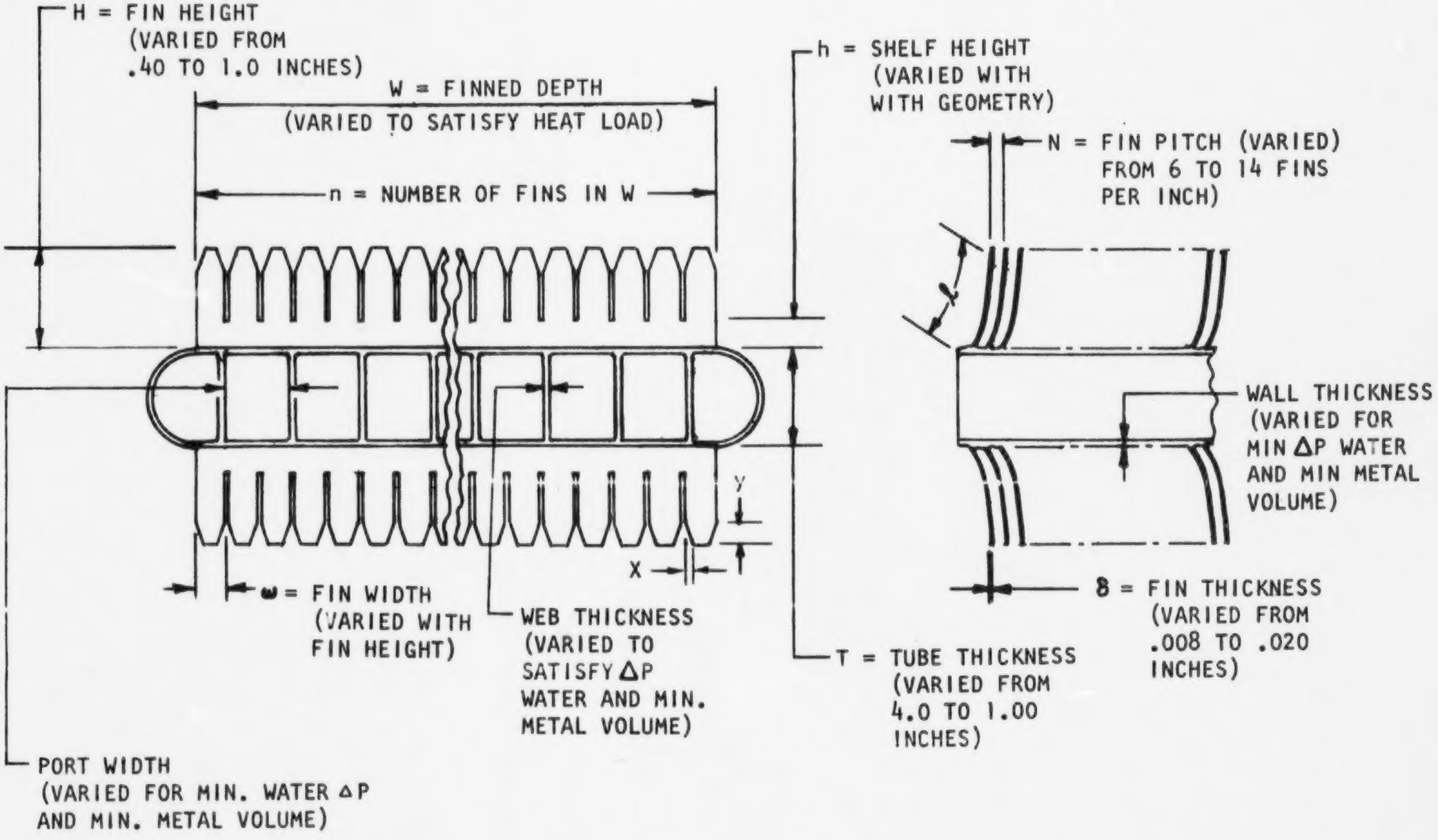

H = FIN HEIGHT (VARIED FROM .40 TO 1.0 INCHES)
W = FINNED DEPTH (VARIED TO SATISFY HEAT LOAD)
n = NUMBER OF FINS IN W
h = SHELF HEIGHT (VARIED WITH WITH GEOMETRY)
N = FIN PITCH (VARIED) FROM 6 TO 14 FINS PER INCH)
γ
WALL THICKNESS (VARIED FOR MIN ΔP WATER AND MIN METAL VOLUME)
Y
X
ω = FIN WIDTH (VARIED WITH FIN HEIGHT)
WEB THICKNESS (VARIED TO SATISFY ΔP WATER AND MIN. METAL VOLUME)
T = TUBE THICKNESS (VARIED FROM 4.0 TO 1.00 INCHES)
δ = FIN THICKNESS (VARIED FROM .008 TO .020 INCHES)
PORT WIDTH (VARIED FOR MIN. WATER ΔP AND MIN. METAL VOLUME)

Figure 6.2. Typical Curtiss-Wright integral-fin multi-port tube(7).

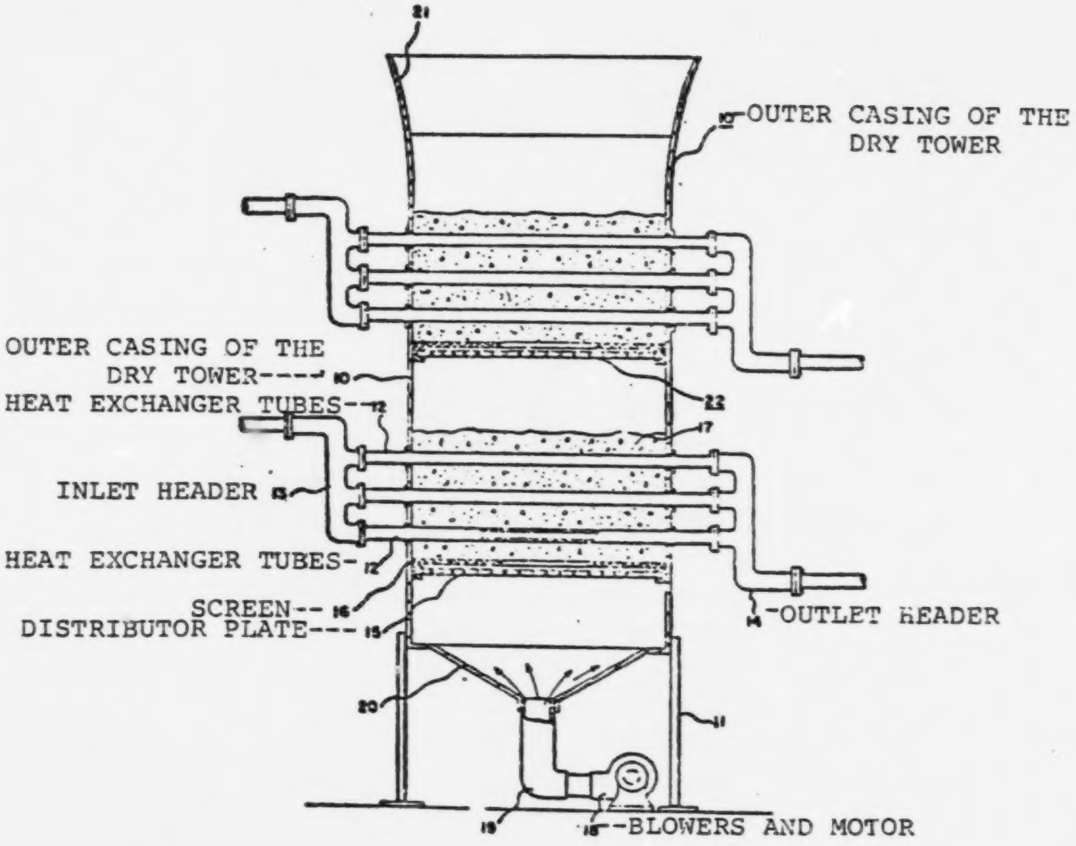

21
10 OUTER CASING OF THE DRY TOWER
OUTER CASING OF THE DRY TOWER 10
22
HEAT EXCHANGER TUBES 12
17
INLET HEADER 13
HEAT EXCHANGER TUBES 12
SCREEN 16
DISTRIBUTOR PLATE 15
14 OUTLET HEADER
20
11
19
18 BLOWERS AND MOTOR

Figure 6.3. Fluidized bed dry tower(9).

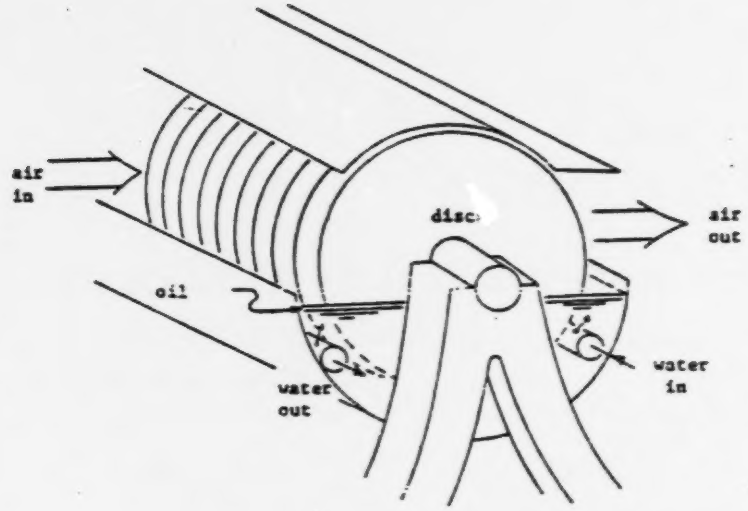

air in
disc
air out
oil
water out
water in

Figure 6.4. Periodic dry cooling tower schematic(10).

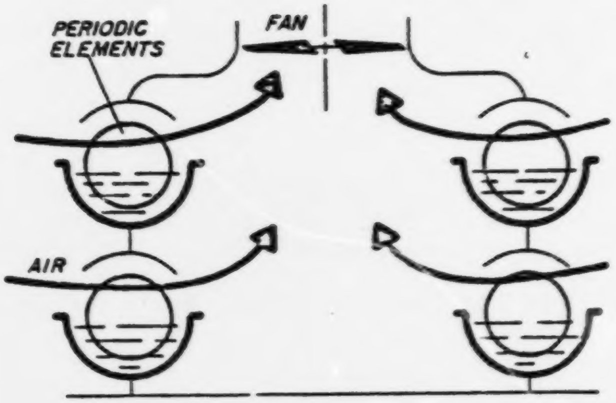

PERIODIC ELEMENTS
FAN
AIR

Figure 6.5. Cross section of a dry cooling tower using periodic cooling elements(10).

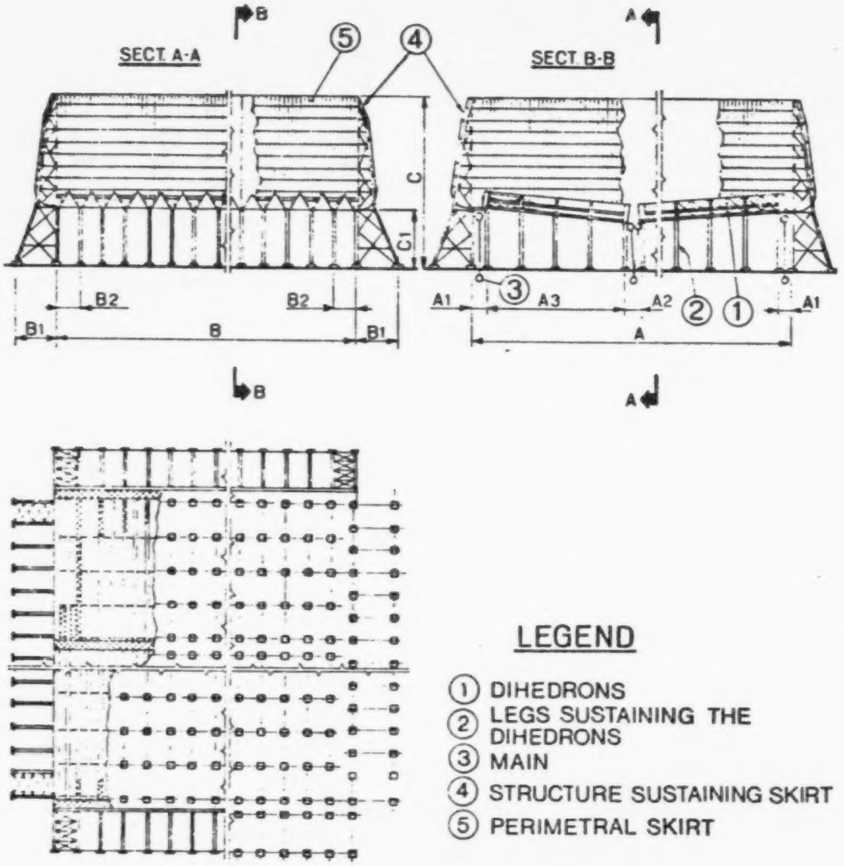

SECT. A-A
SECT. B-B
⑤
④
B
A
C
C1
B1
B2
B
B2
B1
A1
③
A3
A2
②
①
A1
A
LEGEND
① DIHEDRONS
② LEGS SUSTAINING THE DIHEDRONS
③ MAIN
④ STRUCTURE SUSTAINING SKIRT
⑤ PERIMETRAL SKIRT

Figure 6.6. Proposed design of low profile natural draft dry tower using plastic tubes for a 1100-MWe nuclear power plant(11). Reprinted from American Power Conference, 1973, by C. Roma with permission of the American Power Conference.

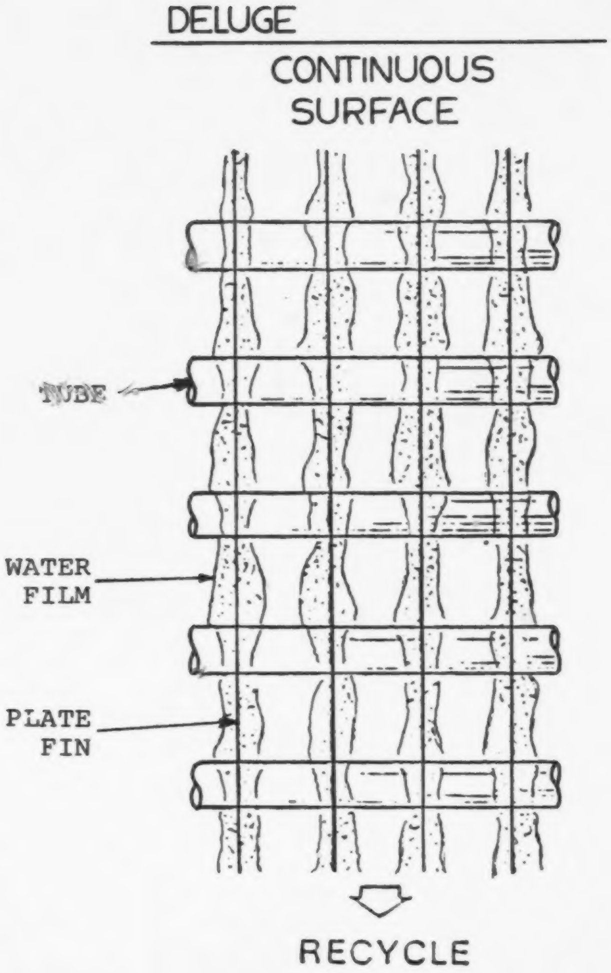
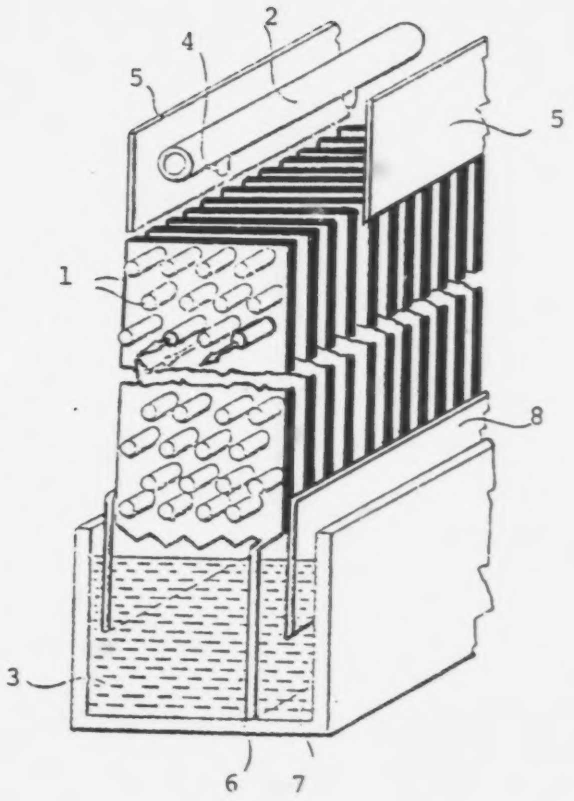

DELUGE
CONTINUOUS
SURFACE
TUBE
WATER
FILM
PLATE
FIN
RECYCLE

Figure 6.7. Plate-fin deluge detail(14).



Legend:
1. Water tubes (horizontal pipes)
2. Water distribution main
3. Water collecting basin
4. Sprinkler heads
5. Protective plates (air flow baffle)
6. Basin partition
7. Cooler water section of base
8. Lower protective plates (air flow baffle)

Figure 6.8. Plate-fin deluge tower arrangement(14).

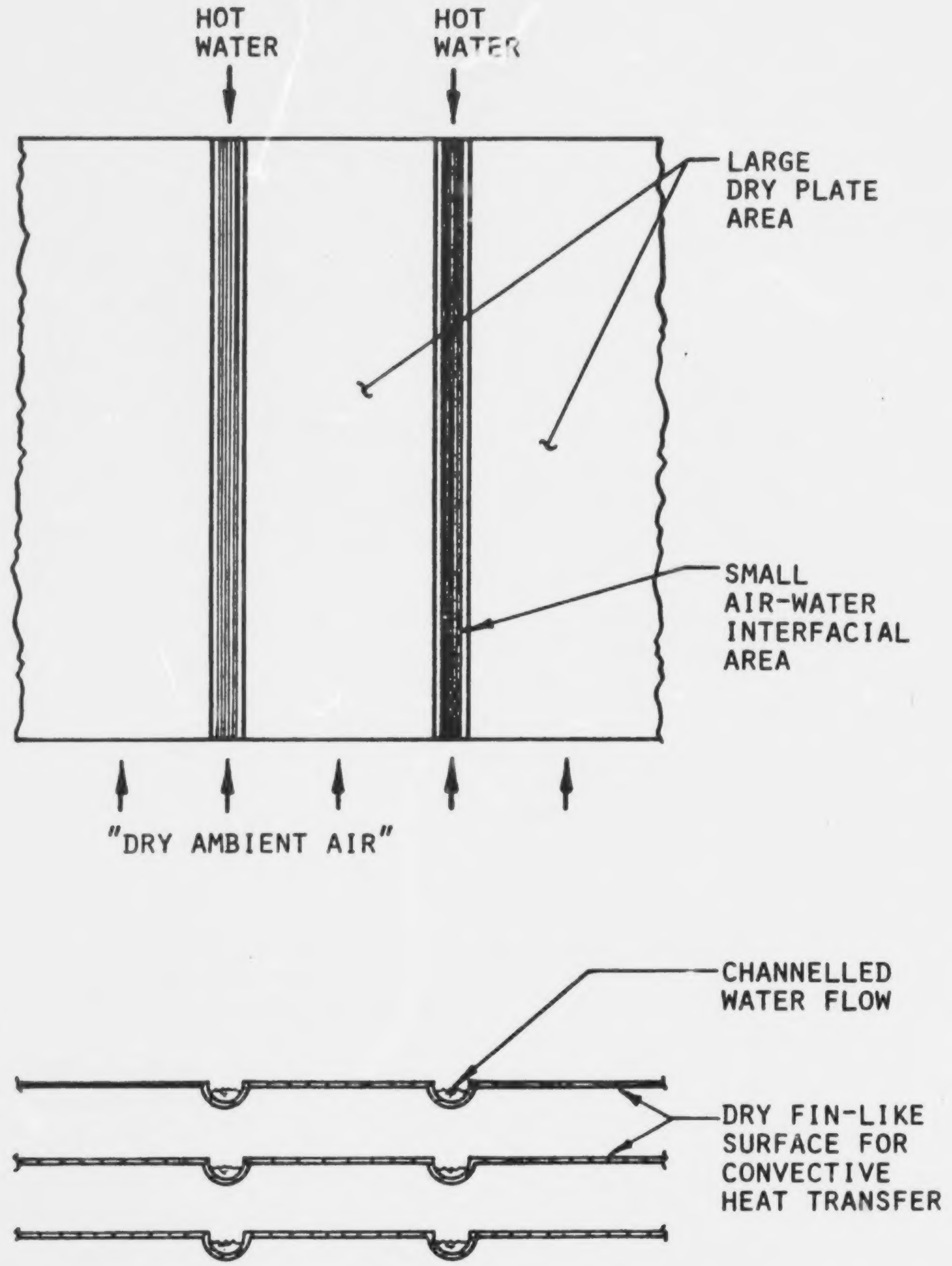

HOT WATER
HOT WATER
LARGE DRY PLATE AREA
SMALL AIR-WATER INTERFACIAL AREA
"DRY AMBIENT AIR"
CHANNELLED WATER FLOW
DRY FIN-LIKE SURFACE FOR CONVECTIVE HEAT TRANSFER

Figure 6.9. Conceptual design of the new wet/dry surface (16).

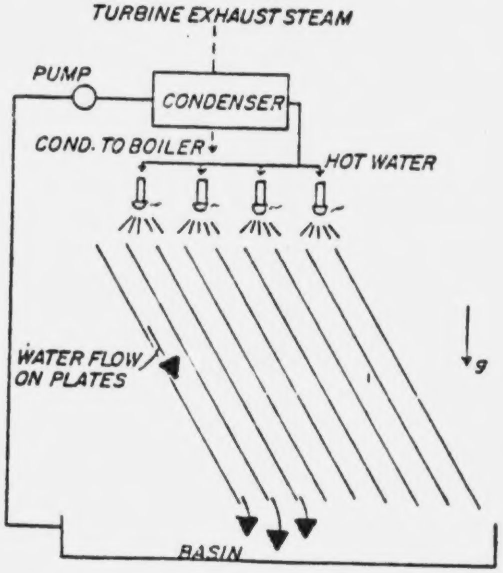

TURBINE EXHAUST STEAM
PUMP
CONDENSER
COND. TO BOILER
HOT WATER
WATER FLOW ON PLATES
g
BASIN

Figure 6.10. Schematic diagram of the MIT advanced wet/dry tower packing arrangement(16).

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SECTION 7

AN OVERVIEW OF CLOSED-CYCLE COOLING WATER TREATMENT

7.1 INTRODUCTION

In light of the national goal of zero discharge and the regulatory limitations on once-through cooling systems, many utilities have turned to closed-cycle cooling for the heat rejection from nuclear- and fossil-fueled power plants(1). Figure 7.1 depicts the basic elements of a typical recirculating cooling tower system. Also shown in this figure are the locations where water treatment may be required for the tower system.

Water is lost from the cooling system through evaporation, drift, and blowdown. Drift is defined as the mechanical entrainment of water droplets in the rising air exhausted from the top of the tower. The term windage has also been used to designate the drift losses. In order to restore the water lost through evaporation and drift, a continuous quantity of make-up water must be added to the recirculating water system.

As water evaporates from a closed-cycle cooling system, dissolved and suspended substances gradually build-up and remain in the recirculating cooling water. In order to control this build-up to reasonable levels, a quantity of the recirculating water is purposely discharged on a continuous basis. The cooling water discharged is called blowdown, and it must be replendished by make-up water to maintain the water balance. Thus, neglecting minor losses, the rate of make-up for a cooling system in the form of evaporation, drift, and blowdown rates can be expressed as:

$$\text{Make-up} = \text{Evaporation} + \text{Drift} + \text{Blowdown} \qquad (7.1)$$

The ratio of the concentration of a constituent in the recirculating cooling water to its original concentration in the make-up water is defined in cooling water treatment as the number of cycles of concentration, C. Operation with high cycles of concentration will reduce both the make-up and blowdown flow rates. However, high cycles of concentration also create or aggravate the problems associated with the cooling water systems, because the increased concentration of dissolved solids forces extensive water treatment to enable the system to operate satisfactorily.

In this and the ensuing three sections (Sections 7 through 10), descriptions and/or discussions are provided for the following areas concerning water treatment in the closed-cycle cooling systems: 1) problems associated with the operation of cooling water systems, 2) restrictions on blowdown, 3) the current, near-horizon and future technologies for water treatment, and 4) the typical costs of water treatment.

7.2 RELATIONSHIPS BETWEEN CYCLES OF CONCENTRATION AND THE FLOW RATES OF MAKE-UP AND BLOWDOWN

The relationship between cycles of concentration and the flow rates of make-up and blowdown of a wet cooling tower can be derived from the mass balances of water and the dissolved solid constituents in the water entering and leaving the tower (Figure 7.2):

Water Balance:

$$M = E + B + D \qquad (7.2)$$

Mass Balance of Dissolved Solid Constituents:

$$MC_M = BC_B + DC_B \qquad (7.3)$$

where:

M = make-up flow rate.

E = evaporation rate.

B = blowdown flow rate.

D = drift rate.

C_M = concentration of dissolved solids in the make-up stream.

C_B = concentration of dissolved solids in the circulating water.

Solving Equations (7.2) and (7.3),

$$\frac{B}{E} = \frac{1}{C-1} - \frac{D}{E} \qquad (7.4)$$

and

$$\frac{M}{E} = \frac{C}{C-1} - \frac{D}{E} \qquad (7.5)$$

where:

$C = C_B/C_M$, is the number of cycles of concentration of total dissolved solids in the circulating water as defined in Section 7.1.

Equations (7.4) and (7.5) are plotted in Figure 7.3. The figure shows that when the evaporation rate is constant the flow rates of both the make-up and blowdown from the cooling tower decrease as the number of cycles of concentration increases.

Thus, in some existing cases or to meet future requirements, it may be desirable to operate recirculating systems at a high number of cycles of concentration if the ultimate objective is to operate at as low a make-up water requirement and/or at as low a blowdown rate as possible. The reduction of the make-up requirement is an objective where water is scarce; the reduction of blowdown is an objective where there may be strict limits on the discharge allowed or where no discharge is allowed to a receiving stream. In the latter case, a reduction of blowdown is important in reducing the size and cost of blowdown treatment.

7.3 PROBLEMS ASSOCIATED WITH COOLING WATER SYSTEMS

Generally, the major objectives of water quality control in cooling tower systems are to ensure that the water: 1) does not degrade the thermal efficiency and 2) does not reduce the life expectancy of major pieces of equipment, such as towers, pumps, condenser tubes, etc. It is usually more economical to maintain water quality within certain limits than to face frequent equipment maintenance and replacement.

The three major types of problems associated with cooling tower systems are scaling, fouling, and degradation of materials in contact with the recirculating cooling water. Scaling is the result of chemical precipitation and deposition of dissolved salts. Fouling can result from the deposition of suspended and entrained solid materials and biological growth. Degradation problems are largely confined to corrosion of the metal surfaces and deterioration and decomposition of the internal components used in cooling towers. A brief discussion of each of these major areas of concern follows.

7.3.1 Scaling

Scaling results when dissolved salts are allowed to concentrate beyond their solubility limits and begin to precipitate and form deposits on the walls of pipelines and heat exchange surfaces. Scaling can result in a loss in heat transfer effectiveness and eventual clogging of the condenser tubes. Table

7.1 presents a typical analysis of scales from a power plant condenser(3).

The most common type of scaling results from the precipitation of calcium carbonate. Calcium carbonate is formed by the conversion of bicarbonate to carbonate at the elevated temperatures reached in the condenser. High concentrations of calcium bicarbonate are found in many freshwater sources in the United States and are the prime sources of calcium carbonate resulting in scale formation. Table 7.2 depicts the maximum and minimum concentrations of selected chemical constituents observed from samples of 98 rivers in the United States(4).

In general, most scale deposits are formed by the combination of the "hardness" cations of calcium and magnesium with the bicarbonate, sulfate, and silicate anions. In some instances, the iron and manganese cations can also participate in scale formation. Several of the scale deposits, such as calcium carbonate and sulfate, exhibit decreasing solubility with increasing temperature. Figure 7.4 depicts the relationship between solubility and temperature for several types of scale deposits(5). The silicates are more frequently encountered in the western portions of the United States and, when associated with magnesium, can form dense scales.

7.3.2 Fouling

The term fouling is normally used to describe the accumulative formation of types of deposits other than scales within the recirculating water system. As in the case of scaling, fouling can reduce heat transfer effectiveness and can eventually clog condenser tubes. Fouling is usually the result of physical or biological processes rather than chemical reactions. Some of the more frequent sources of materials which contribute to fouling include(5,6):

1. Silt, sand, clay, metal oxides, detritus, microorganisms, and debris introduced with the make-up water

2. Atmospheric contaminants, such as dust, soot, pollens, spores, and insects introduced through the cooling system

3. Biomass sloughed off the cooling surfaces and entrained in the cooling water

4. Oil from leaks and present in make-up water

5. Corrosion products, precipitates, and loosened scale from the cooling system itself

6. Biological growth of algae, fungi, bacteria, and slimes within the cooling system.

In cooling water systems using sea water, additional higher order organisms (such as barnacles, bryozoans, sponges, and tunicates) can produce fouling problems, particularly at the intake structures. Table 7.3 lists some of the more common organisms responsible for biological fouling(5).

Biological fouling can be caused by microorganisms generally classified as algae, bacteria, fungi, and molds(7). The algae require light to survive, so they are usually confined to the exposed areas of cooling towers and ponds. Bacteria, however, can survive and flourish within the recirculating water piping and condenser tubes under either aerobic or anaerobic conditions. Both algae and bacteria can produce slimes, which can serve as points of attachment for the inorganic forms of fouling. One family of anaerobic bacteria is capable of reducing sulfates to hydrogen sulfide. The hydrogen sulfide in turn can react with the steel to produce a deeply pitted form of corrosion. These anaerobic conditions can exist at the bottom of cooling ponds or beneath fouling deposits.

Some of the principal factors which influence the rate of microbial growth include the dissolved oxygen concentration, the dissolved organic content of the water, water velocity, temperature, and sunlight.

7.3.3 Corrosion

Corrosion is an electro-chemical reaction which results when electrical cells, which consist of anode and cathode surfaces, are formed on the metal surfaces in contact with the cooling water. The cooling water and the metal itself act as the pathways for completing the circuit for a galvanic electrical cell. Although corrosion can also result from the dissolution of metal by free mineral acidity, this is an exception which requires special consideration. Here, only galvanic cell types of corrosion are considered.

Figure 7.5 schematically depicts the first stage of a corrosion reaction involving iron and dissolved oxygen. At the anode, iron is dissolved to produce a ferrous ion and two electrons. The ferrous ion goes into solution. The two electrons migrate to the cathode through the metal conductor and complete the circuit at the cathode. The electrons interact with dissolved oxygen and water to form hydroxyl ions. The hydroxyl ions react with the excess ferrous ions dissolved from the anode to form and deposit ferrous hydroxide at the cathode. In actuality, the anode and cathode are often at the same physical location. The corrosion reaction proceeds in several stages, corresponding to the various oxidation states of the metal. These stages can be observed by differences in color of the corrosion products.

Of the various possible corrosion reactions which can occur at the anode, the reactions having the highest half cell potential will prevail. Similarly, at the cathode, the cathode reactions having the lowest potential will occur. The combined potential for a given reaction can be computed by subtracting the half cell potential for the cathode from that of the anode.

The corrosion cell illustrated in Figure 7.5 is greatly simplified. In reality several competing reactions occur during corrosion. The corrosiveness of water is dependent upon the metal ions present, the other molecules and ions present which can enter into the oxidation-reduction reaction, and the films covering the metal surface. Certain metals and alloys, such as aluminum, form a protective layer during corrosion, which tends to deter further corrosion. Iron, on the other hand, when corroding may experience significant surface degradation before a protective layer is formed. For other materials, no protective layer may be formed, and the reaction may continue until the metal is wasted. Such materials are frequently used as a sacrificial material in corrosion protection systems.

Most corrosion originates because of irregularities in the metal surface due to impurities in the metal, joints, metal alloying, deposition of scale or fouling deposits, and temperature and dissolved oxygen gradients. Some of the major waste characteristics which influence the rate of corrosion include pH, dissolved solids, alkalinity, temperature, velocity, dissolved oxygen concentration, and the presence of other oxidants.

Dissolved oxygen plays a dual role in metallic corrosion(8). In several of the half cell reactions which occur during corrosion, hydrogen ions are reduced to elemental hydrogen at the cathode. If left undisturbed, this elemental hydrogen would form a protective coating at the cathode which would limit the rate of corrosion. The presence of dissolved oxygen prevents this accumulation, since hydrogen reacts with the elemental oxygen to form water. On the other hand, high concentrations of dissolved oxygen can lower the probability of corrosion by forming anodic films at the anode. In most instances, cathodic reactions control the early stages of corrosion. Thus, the presence of dissolved oxygen or some other oxidizing agent is required in order to initiate the early state of corrosion.

In closed-cycle cooling systems, dissolved oxygen is usually present, especially in a cooling tower system. Consequently, corrosion protection is an important consideration in these systems.

7.3.4 Deterioration of Wood and Asbestos Cement Components

The internal components of a cooling tower have been fabricated from a variety of materials, such as asbestos-cement, plastics, ceramics, and wood. The internal components of most of the wet towers presently in use are made of wood or asbestos-cement. In the past, wood has been used as a structural element in many small mechanical draft cooling towers. Wood deterioration in wet cooling towers can occur by a combination of chemical, biological, and physical mechanisms(7).

Chemical action can cause delignification of the wood. The extent of delignification is primarily influenced by the alkalinity of the recirculating cooling water. Wooden material usually exhibits a white fibrous appearance as a result of this form of deterioration(9).

Fungus attack can cause a reduction in the cellulose content of the wood and produce a crumbly surface in the areas affected. Physical factors, such as high temperatures, high dissolved solids content, and alternating freezing and thawing, can cause wood splitting and general deterioration. Consequently, the material most commonly used in large natural draft cooling towers is asbestos-cement or asbestos paper. This material is highly resistant to breakdown due to freeze-thaw cycles, biological attack, and chemical deterioration. However, breakdowns do occur, particularly if a highly corrosive water is used for cooling. Salt water can also cause deterioration of the asbestos-cement fill if this fill is wetted on one side only; casings and louvers are particularly susceptible. Microorganisms can also cause damage when attached to the asbestos-cement components.

7.3.5 Scaling and Corrosion Indices

Since calcium bicarbonate is the major source of scale for most cooling tower applications, two indices based on the bicarbonate equilibrium equations are commonly used. The Langelier Index, defined as the difference between the actual pH of the water and its saturation pH, is a measure of the relative scaling and corrosion potential of a given water. Thus,

$$\text{Langelier Index} = \text{pH} - \text{pH}_s \qquad (7.6)$$

where pH_s is defined as the saturation pH at which the water would be in equilibrium with the calcium carbonate.

Thus, if the pH is greater than the saturation value, (i.e., a positive Langelier Index), there will be a tendency to deposit calcium carbonate, while at negative values of the Langelier Index there will be a tendency to dissolve existing carbonate deposits.

The saturation pH is a function of the calcium ion concentration, the total alkalinity, the temperature, and the disassociation constants for the carbonate-bicarbonate equilibrium. In its complete form(7),

$$pH_s = \log \frac{K_s}{K_2} - \log(Ca^{++}) - \log A + 6.301 + S \qquad (7.7)$$

where:

K_s = solubility constant of calcium carbonate and

$$K_s = \frac{(Ca^{++}) \quad (CO_3^{=})}{CaCO_3}$$

K_2 = disassociation constant of calcium bicarbonate and

$$K_2 = \frac{(H^+) \quad (CO_3^{=})}{(HCO_3^{-})}$$

A = total alkalinity.

S = salinity term = $\frac{2\ N}{1 + N}$

N = ionic strength = $2.5 \times 10^{-5} C_s$.

C_s = salinity concentration.

and Ca^{++}, $CO_3^{=}$, H^+, and HCO_3^- are ionic concentrations of the various constituents.

The Ryznar Stability Index is similar to the Langelier Index in that it is also derived from the actual pH and the saturation pH.

$$\text{Ryznar Index} = 2(pH_s) - pH \qquad (7.8)$$

The Ryznar Index was empirically derived from a study of operating data for waters of various saturation indices. Values of the Ryznar Index below 6.0 indicate increasing corrosion potential. Figure 7.6 presents a typical nomograph for determination of the Langelier and Ryznar Indices(10). Both the Langelier and Ryznar Stability Indices do not provide absolute criteria for design and operation, but constitute guidelines to develop and achieve treatment objectives.

Many recirculating cooling water systems operate at a slightly scaling condition(11). The objective of this type of operation is to develop a calcium carbonate film on the metal surfaces to prevent or retard corrosion. This film breaks the circuit of galvanic corrosion cells by electrically insulating the water from the metal(12). However, care must be exercised so that the film does not become so thick that it reduces heat transfer significantly or clogs condenser tubes. While calcium carbonate deposition for corrosion control is widely practiced, the development of corrosion resistant alloys and chemical inhibitors now makes it possible to operate at slightly corrosive conditions in some systems(11).

7.4 CIRCULATING WATER QUALITY LIMITATIONS

In order to minimize the amount of blowdown and make-up water required and their associated treatment costs, it is desirable to operate the system at the highest cycles of concentration possible. This will become increasingly important for the "zero discharge" goal to become a reality. As the number of cycles of concentration increases, the concentration of the chemical constituents in the recirculating water increases by the same factor. In order to maintain these constituents within acceptable limits to minimize scaling and corrosion, certain guidelines have been proposed by Crits and Glover(13). Table 7.4 summarizes these guidelines.

The "conventional low pH" values in Table 7.4 are based on traditional operating concepts. The higher values noted under the "high pH, high cycles of concentration" column are those attainable through the use of organic additives or dispersants. It should be noted that a lower guideline of 500,000 for the solubility product of calcium and sulfate has been cited by others (14). As the demand for operation at higher cycles of concentration becomes necessary, pilot plant operation early in the design stage may become useful to establish design and operating parameters.

In order to compute the maximum number of cycles of concentration allowable without exceeding any of the limits noted in Table 7.4, the initial quality of the make-up must be known. For example, if the initial silica concentration in the blowdown water is 20 mg/l, the 150 mg/l limitation would be reached after 150/20 or 7.5 cycles of concentration.

Various types of treatment can be applied to reduce the concentration of the limiting constituent in order to achieve higher cycles of concentration. However, the cost of providing the treatment must be compared to the benefits of reduced make-up or blowdown. The environmental impact of the additional chemicals and the disposal of the resulting residue must also be factored into this comparison. The various treatment processes available for cooling water treatment are described in Section 9.

7.5 RESTRICTION ON BLOWDOWN

Current Federal Regulations place restrictions on blowdown temperature and combined chlorine residual as part of the 1977 "Best Practical Technology Currently Available" (BPTCA) limitations(15). The "Best Available Technology Economically Achievable" (BATEA) limitations for 1983 place limitations on free and combined chlorine residuals, zinc, phosphorus, and chromium, and provide for a case by case evaluation of other corrosion inhibiting materials. The 1974 Guidelines, which delineated BPTCA and BATEA limitations, are under court remand. Revised Federal Guidelines are in preparation and are expected to be promulgated in 1979. Regulations for the discharge of other contaminants or residues resulting from treatment of the recirculating cooling water are primarily controlled by state and local regulations concerning sludge disposal and the water quality criteria for specific water bodies.

In the past, blowdown quantities were largely determined by the circulating water quality limitations discussed in the previous section. If the cost to treat make-up water was low, the system was operated at low cycles of concentration to minimize the build-up of suspended and dissolved solids. If the cost to treat make-up water and adding treatment chemicals to the circulating water was high, the system was operated at as high a cycles of concentration as possible in order to minimize treatment cost while maintaining the quality of the recirculating water within the limits presented in Table 7.4. In the future, water quality limitations and treatment of blowdown waste must be included in this determination.

For example, consider a make-up having a high initial phosphorous level. This phosphorous could concentrate beyond the 5 mg/l level allowed for cooling tower blowdown (1983 BATEA), if the cycles of concentration is set at a high level based on the circulating water quality limitations. This would require blowdown treatment to remove some of the phosphorous or operation of the system at a reduced value for the cycles of concentration. Future bans on the discharge of some of the chemicals used for corrosion, scaling, and wood deterioration control may also impact the number of cycles of concentration at which circulating cooling systems can be operated. Trends toward zero discharge will encourage the use of very high cycles of concentration to reduce blowdown quantities.

In some power plants it may become practical to reuse cooling tower blowdown for other purposes, such as ash sluicing water. In such cases, the water quality limitations of the ash handling sluicing water may also influence the cycles of concentration and optimum blowdown quantities. As the emphasis on improving the environment places more stringent controls on blowdown disposal, the increasing cost of blowdown treatment and residue disposal will have a major impact on the specification of blowdown quantities.

TABLE 7.1. TYPICAL ANALYSIS OF SCALES FROM POWER PLANT CONDENSER SYSTEMS(3)

Source	Percent of Total Product
Calcium as CaO	49.79
Magnesium as MgO	2.42
Iron as Fe_2O_3	0.61
Aluminum as Al_2O_3	0.21
Carbonate as CO_2	39.00
Sulfate as SO_3	1.29
Silica as SiO_2	0.15

TABLE 7.2. MAXIMUM AND MINIMUM VALUES OF SELECTED WATER QUALITY PARAMETERS FOR 98 RIVERS(4)

Parameter	Minimum Concentration (mg/l)	Maximum Concentration (mg/l)
Hardness as $CaCO_3$	15	589
Calcium as $CaCO_3$	11	408
Magnesium as $CaCO_3$	3	181
Sodium and Potassium as $CaCO_3$	4	774
Bicarbonate as $CaCO_3$	14	256
Chlorides as $CaCO_3$	1	702
Sulfates as $CaCO_3$	4	473
Nitrates as $CaCO_3$	0.1	10
Iron as Fe	0.02	3
Silicate as SiO_2	8	48

TABLE 7.3. TYPES OF BIOLOGICAL GROWTH AFFECTING OPERATION OF RECIRCULATING COOLING WATER SYSTEMS(5)

Growth Type	Examples	Problems Caused
Green algae	Chlorella Ulothrix Spirogyra	Heavy growths in spray ponds and cooling towers can interfere with water distribution, plug screens, and restrict flow in pipelines and pumps. Algae can accelerate pitting-type corrosion when they adhere to metal. Massive growths handicap microbiological control by absorbing biocides.
Blue/green algae	Anacystis Phormidium Oscillatoria	
Diatom algae	Flagiaria Cyclotella Diatoma	
Mold-type filamentous fungi	Aspergillus Pencillium Mucor Fusarium Alternaria	Promote surface rot of cooling tower wood; produce bacteria-like slimes
Yeastlike fungi	Torula Saccharomyces	Discolor cooling water and wood
Higher fungi (Basidiomycetes)	Poria Lenzites	Cause severe internal rot in cooling tower wood
Aerobic capsulated bacteria	Aerobacter Flavobacterium Proteus Pseudomonas Serratia	Promote the growth of several bacterial slimes
Aerobic spore-forming bacteria	Bacillus	Produce bacterial slimes; spores difficult to kill
Sulfur bacteria (aerobic)	Thiobacillus	Produce sulfuric acid from oxidized sulfur or sulfides
Sulfate reducing bacteria (anaerobic)	Desulfovibrio	Grow under aerobic slime, causing corrosion; form hydrogen sulfide

(continued)

TABLE 7.3 (continued)

Growth Type	Examples	Problems Caused
Iron bacteria	Crenothrix Leptothrix Gallionella	Produce bulky slime deposits; precipitate ferric hydroxide

TABLE 7.4. CONTROL LIMITS FOR COOLING TOWER CIRCULATING WATER COMPOSITION(14)

	Conventional at Low pH	Suggested at High pH with High Cycles of Concentration with Dispersants
pH	6.5 to 7.5 ±0.5	7.5 to 8.5 ±0.3
Suspended solids (mg/l)	200-400	300-400
Carbonates, CO_3 (mg/l)	5	5
Bicarbonates, HCO_3 (mg/l)	50-150	300-400
Silica, SiO_2 (mg/l)	150	150-200
Mg x SiO_2[(a)] (mg/l)	35,000	60,000[(b)]
Ca x SO_4[(a)] (all as $CaCO_3$) (mg/l)	1,500,000 to 2,500,000	2,500,000 to 8,000,000
Ca x CO_3[(a)] (all as $CaCO_3$) (mg/l)	1,200	6,000[(b)]
Ca x Mg x $(CO_3)^2$ (mg/l)	--	2,000,000 to 4,000,000
Chlorides, Cl	No limit[(c)]	No limit[(c)]
COD, BOD, NH_3	Limit depends on type of biocide used.	

(a) Solubility product, e.g., (Mg, m/g) x (SiO_2, mg/l)

(b) More data are needed to confirm this value.

(c) For stainless steel in the cooling system, chlorides must be below 3,000 mg/l.

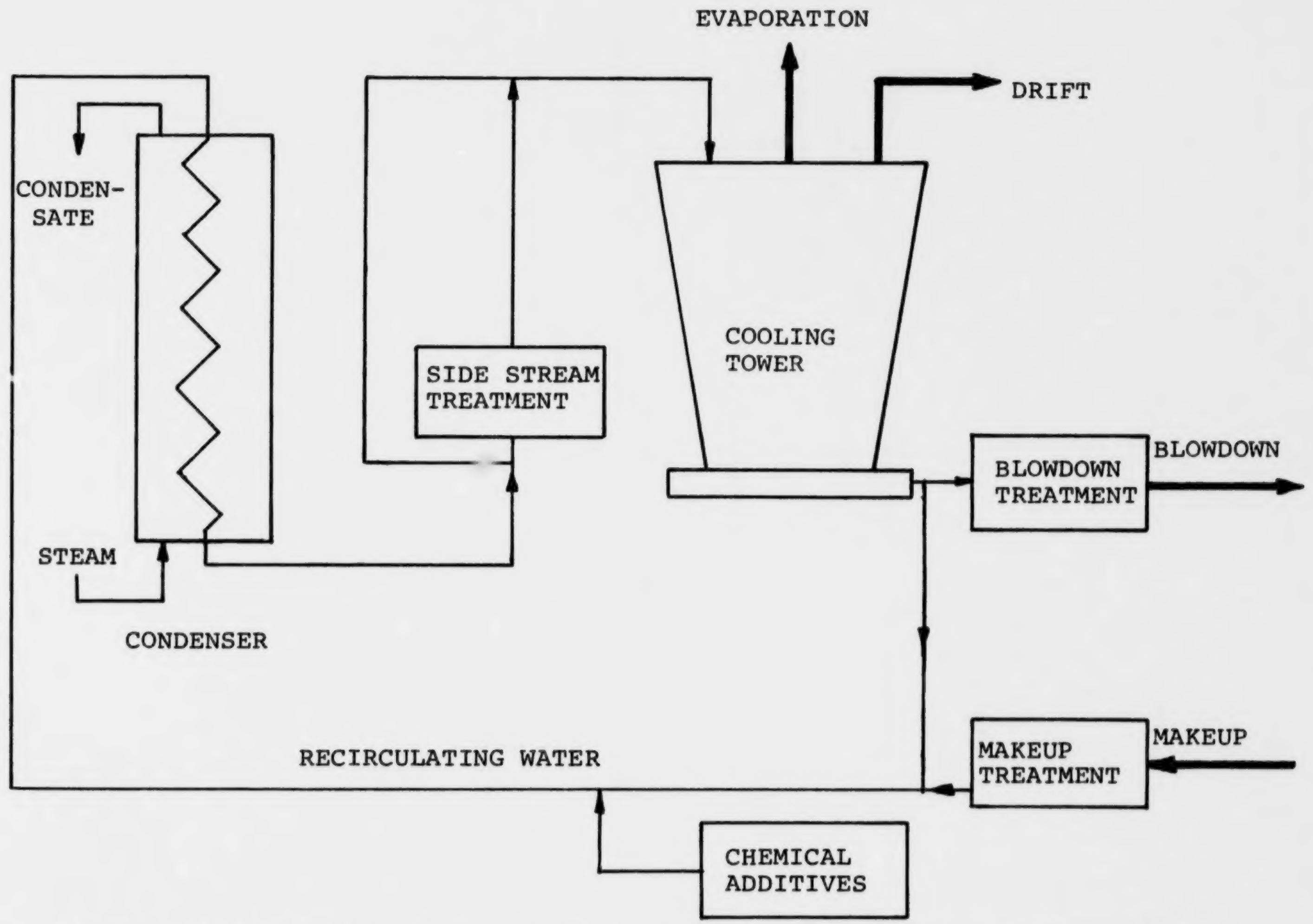
EVAPORATION
DRIFT
CONDEN-
SATE
SIDE STREAM
TREATMENT
COOLING
TOWER
BLOWDOWN
BLOWDOWN
TREATMENT
STEAM
CONDENSER
MAKEUP
MAKEUP
TREATMENT
RECIRCULATING WATER
CHEMICAL
ADDITIVES

Figure 7.1. Locations for potential water treatment in a wet tower system.

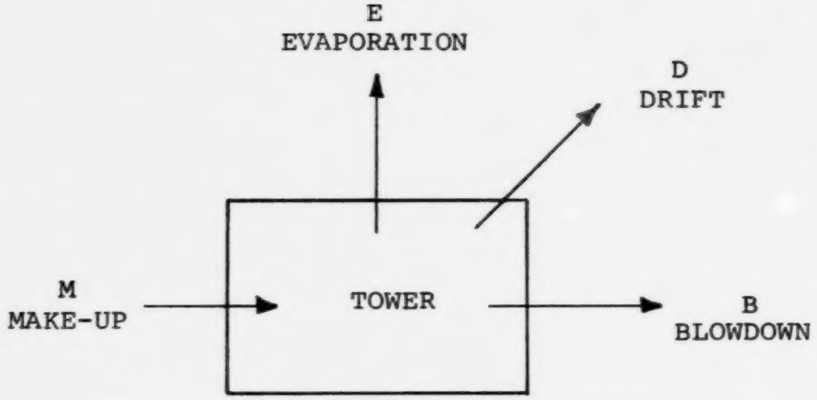
E
EVAPORATION
D
DRIFT
M
MAKE-UP
TOWER
B
BLOWDOWN

Figure 7.2. Mass balance for an evaporative cooling tower.

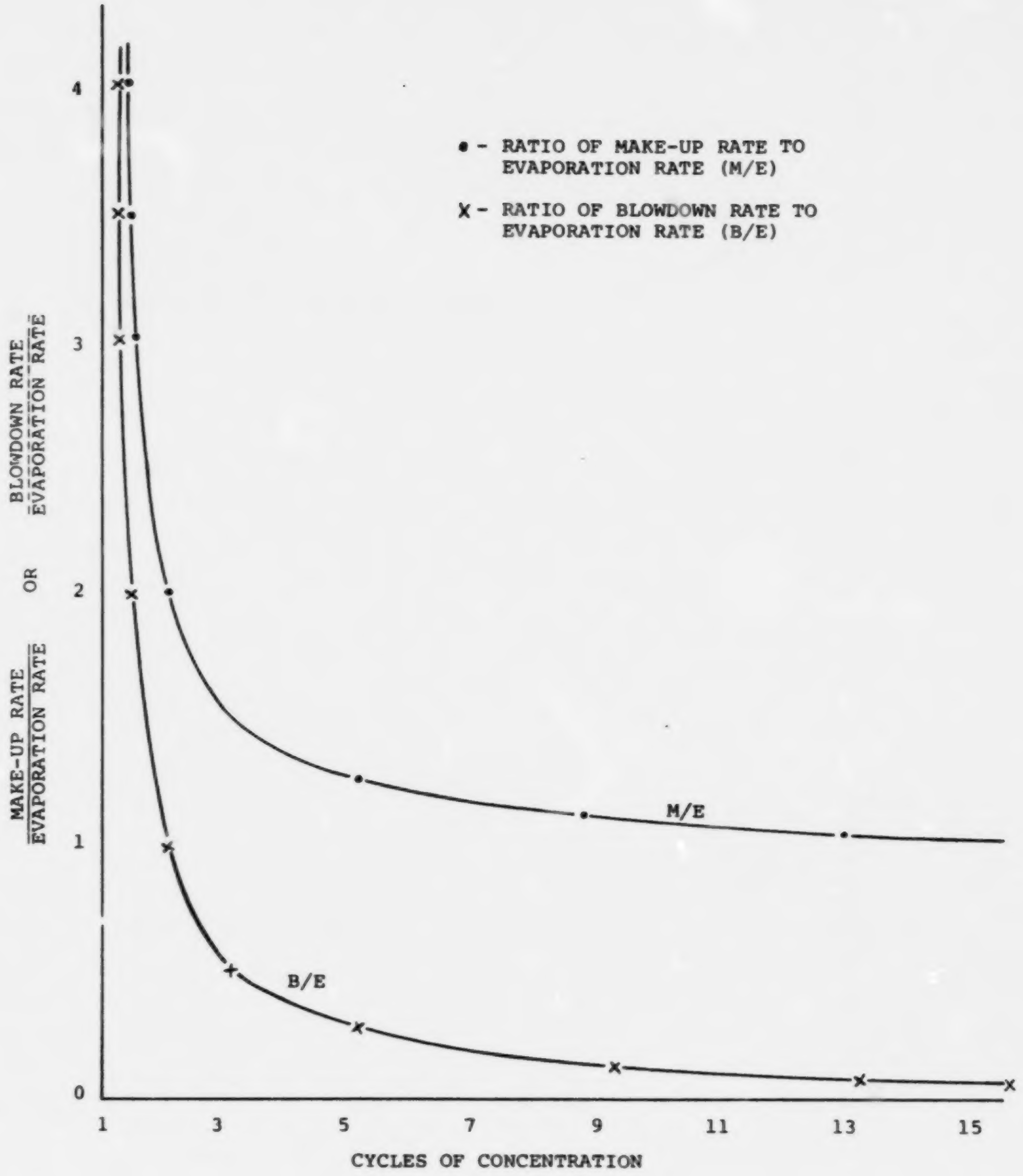

Figure 7.3. Ratio of make-up or blowdown rate to evaporation rate versus cycles of concentration.

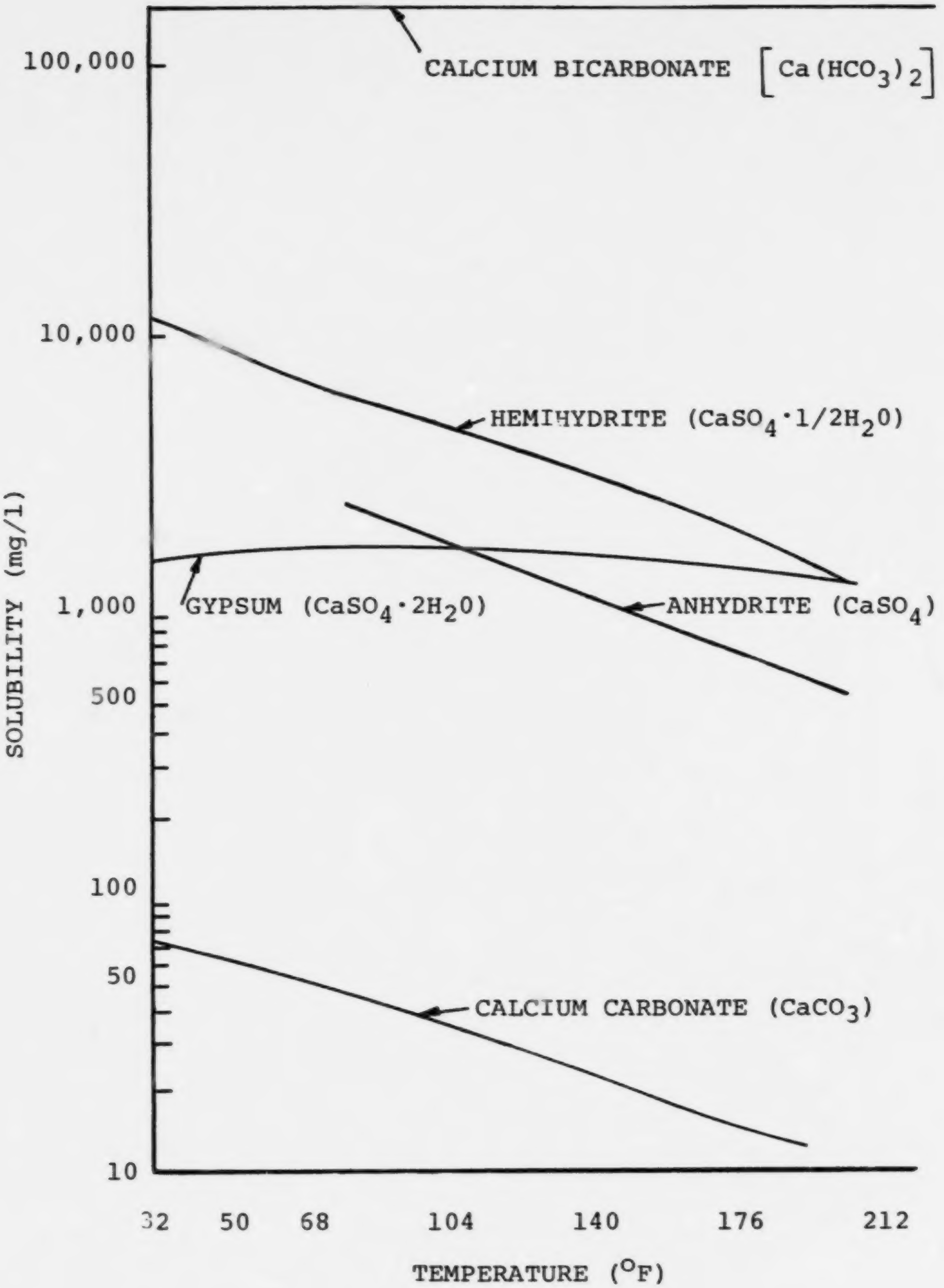

Figure 7.4. Solubilities of selected scale deposits(5).

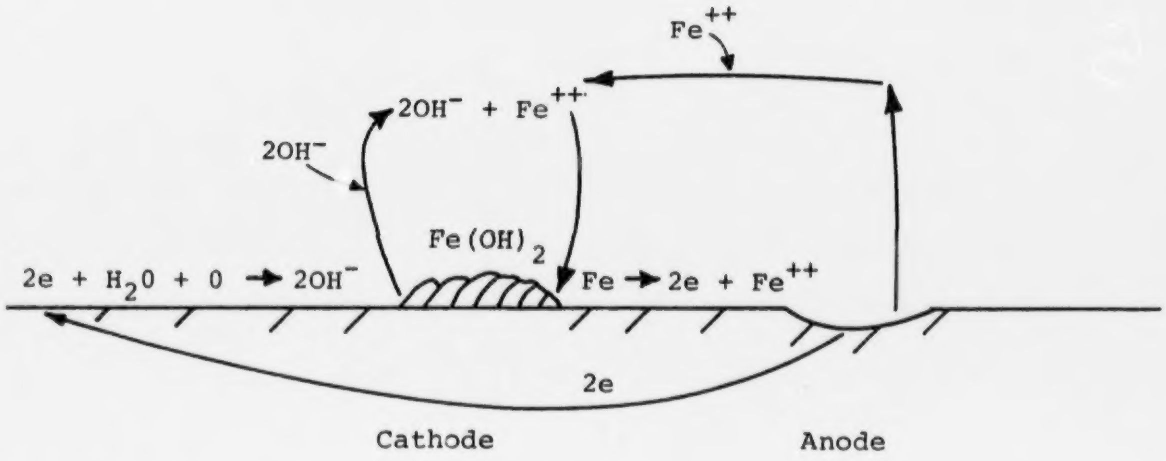
Fe^{++}
2OH$^-$ + Fe^{++}
2OH$^-$
Fe(OH)$_2$
2e + H$_2$0 + 0 → 2OH$^-$
Fe → 2e + Fe^{++}
2e
Cathode
Anode

Figure 7.5. Corrosion reaction schematic.

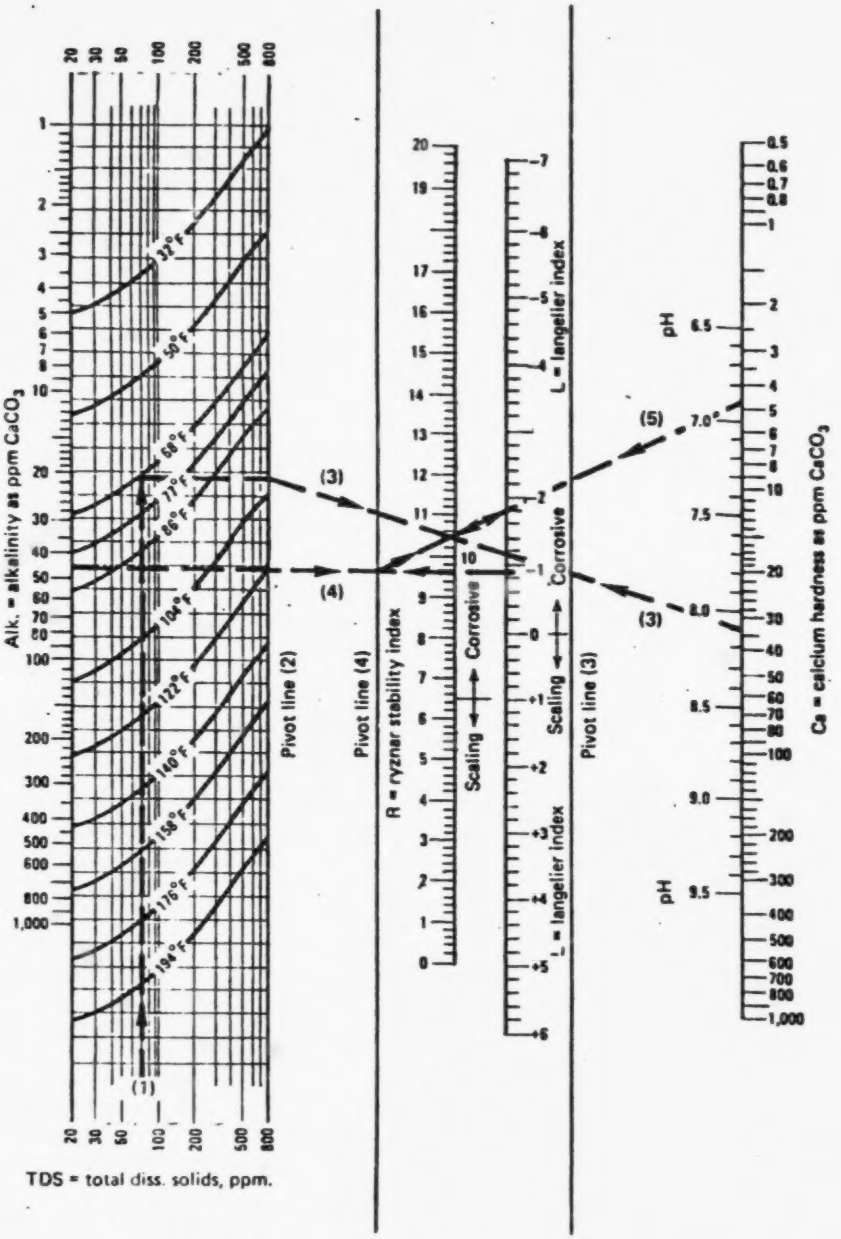

Figure 7.6. Nomograph for determination of Langelier or Ryznar Index(3). Reprinted from Chemical Engineering, 1975, by F. Caplan with permission of McGraw Hill Publication Company.

Figure 7.6 (continued)

Example Illustrating the Use of the Nomograph

Find Langelier Index and Ryznar Index for water with

a) pH = 6.9

b) Total dissolved solids = 72 ppm

c) Calcium hardness = 34 ppm as $CaCO_3$

d) Alkalinity = 47 ppm as $CaCO_3$

e) Temperature = 70°F

Procedure:

1) Find intersection of total dissolved solids at bottom of left curve with temperature

2) Carry this point horizontally to the right to pivot line (2) and connect with calcium hardness on scale at extreme right

3) Note intersection of this line with pivot line (3)

4) Connect this point with alkalinity scale on left via a horizontal line to the left and note intersection with pivot line (4)

5) Connect this intersection to pH and read Langelier Index at intersection with Langelier scale and Ryznar at the intersection with the Ryznar scale.

Solution:

For conditions given in a through e, the Langelier Index, L=-1.8; the Ryznar Index, R=10.4. These values mean that the water has a corrosive tendency.

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SECTION 8

COOLING WATER TREATMENT PROCESSES

8.1 INTRODUCTION

In the past, many utilities have operated closed-cycle cooling water systems with a minimum amount of water treatment. This was possible because of the low cycles of concentration at which the systems were operated and the absence of cooling water blowdown regulations. In the future, water treatment will become common practice for make-up and blowdown quantities. Sidestream treatment of the recirculating water itself may also be necessary to operate at high cycles of concentration. This section describes conventional water treatment processes which can be readily applied for blowdown, make-up, and sidestream treatment of closed-cycle cooling water systems. Only current technology (processes which have been used in the power industry) and near horizon technology (processes which have been extensively applied in related industries) have been included in this section. The majority of the unit processes discussed in this section are near horizon and have not been widely applied for circulating cooling water systems in the power industry. The distinction between current and near horizon processes is discussed further in Section 9. Future technology, which includes processes still in the development stage that lack proven field experience, will be discussed in Section 10. The processes have been conveniently grouped according to their primary function.

8.2 REMOVAL OF SUSPENDED SOLIDS

Suspended solids are defined as the filterable undissolved solids contained in water. They include particle sizes ranging from logs and debris to the finely divided colloidal particles which contribute to the turbidity or cloudiness of water. Their removal is of importance to control fouling and abrasion in a circulating cooling water system. Because of the wide range in particle size associated with suspended solids, several treatment processes have evolved to treat different ranges of particle size.

8.2.1 Screening

Screening is defined as the mechanical removal of large particles of suspended matter and debris from water by passing it through screens. The size of the particles which can be removed by the screen is determined by the size of the screen openings.

The most common types of screens employed in water treatment are bar screens and rotating mesh screens. The bar screens consist of parallel-spaced bars. Many bar screens can be automatically cleaned by passing a mechanical rake through the bars at regular intervals. Rotating screens consist of wire mesh or metal cages mounted on a rotating drum. Rotating screens can be continuously cleaned hydraulically with water jets. A detailed description and a discussion of the environmental impact of these devices is covered in Section 11.

8.2.2 Sedimentation

Sedimentation is defined as the physical separation of suspended solids from water by gravitational forces resulting from differences in specific gravity between the solids and water. Under semi-quiescent conditions, particles which are heavier than water will settle at a velocity which is a function of the particle size, shape, and specific gravity. The relative removal efficiency of an idealized sedimentation process can be directly related to the surface overflow rate of the sedimentation tank and the settling velocity of the particles. Detention time only affects the process to the extent that it affects overflow velocity and provides time for particles to flocculate, thereby, increasing net particle settling velocities.

The principle of gravitational sedimentation applies to grit chambers, sedimentation ponds, and clarifiers. Grit chambers are designed so that the surface overflow velocity is such that only relatively heavy particles with high specific gravity are removed. The function of the grit chamber is to trap sand, grit, silt, and stones to protect mechanical equipment, such as pipes and pumps, from abrasion and to reduce the solids accumulation in subsequent sedimentation devices.

Settling ponds have been used in the past by the power industry for treatment of both blowdown and make-up water for circulating cooling water systems. Settling ponds are usually rectangular or irregularly shaped due either to ease of construction or space availability. Water enters the pond at one end, and particles settle out as the flow traverses the pond. Settling ponds are often not equipped with equipment for automatic sludge removal and must be periodically shutdown and drained to remove sludge accumulation. Detention times are fairly long to provide storage space for deposited solids and to minimize time between shutdowns for sludge removal.

Clarifiers are a more elaborate type of sedimentation device which provides continuous mechanical removal of sludge deposits. Because of the continuous removal feature, detention times can be reduced from days to hours. Clarifiers can be constructed in circular, rectangular or square configurations.

Automatic sludge removal can be accomplished in a variety of ways. In circular tanks, rotating rakes often revolve around the center of the tank pushing sludge to an outlet at the bottom of the tank. Rectangular tanks often utilize chain and flight collectors, which scrape the sludge to a sump from which it is pumped from the clarifier. Traveling bridges which scrape the sludge in either direction or pick up the sludge directly through a hydraulic "vacuum cleaner" are also coming into common use in some clarifier designs.

Many clarifier designs also incorporate chemical feed systems, coagulation zones, thickening zones, collecting launders, and other accessory equipment.

8.2.3 Filtration

Filtration is a process which removes suspended solids from water by passing the water through a bed of porous media. Solids are retained within the porous media through a combination of physical screening of particles larger than the pores of the filter, through gravitational settling, and through adhesion to the filter media by particles entering the filter pores. Filters can employ any combination of filter media ranging from gravel, fine sand, and anthracite to diatomaceous earth. Some filters utilize a pre-coating agent to form a fine mat on the filter surface to improve the capture of fine particles.

Filters can be of either the gravity or pressure type. Gravity filters are more often used where a large volume of water is being filtered. Pressure filters, which usually employ deep beds of graded media, have been used widely for industrial installations. Pressure filters normally operate at higher loading rates 5-10 gpm/ft^2 (3.4-6.8 l/sec/m^2), than gravity filters 2-4 gpm/ft^2 (1.4-2.8 l/sec/m^2), and require less space(1).

As suspended solids are removed by the filter media, the pressure loss across the filter bed is increased and accompanied by a reduction in the flow rate through the filters, unless corrective action is taken. As the filter media becomes filled with the entrapped suspended solids, it becomes necessary to clean the filter to reduce pressure loss and prevent breakthrough of the suspended solids in the filter effluent. Backwashing (reversal of flow to clean the filter) is normally activated when the pressure loss across the filter exceeds a specified value. The frequency of backwashing is related to the suspended solids concentration in the feedwater. Filter backwash cycles typically operate at backwash rates of 10 to 20 gpm/ft^2 (6.8-13.6 l/sec/m^2) of surface area for a backwash time of about 10 minutes(2). The quantities of waste water produced during a backwash cycle can represent a sizable quantity of water being released over a very short time(1). This backwash flow will typically exceed two percent of the filter throughput. If environmental regulations prohibit the direct discharge of filter backwash, this waste water may have to be treated. Often this discharge goes to the chemical waste treatment facility and is mixed with other discharges for further treatment prior to discharge.

8.2.4 Coagulation

Coagulation is the process by which the double layer of electrical charges surrounding colloidal particles is neutralized. Through the reduction in the magnitude of charge of this double layer, the colloids are destabilized, allowing the Van der Waal attractive forces and Brownian Motion to bring about collision and agglomeration of the colloidal particles(3). The chemicals which bring about this coagulation phenomenon are called coagulants. The most common types of inorganic coagulants used for water treatment include inorganic salts, such as alum, ferric sulfate, ferrous sulfate, sodium aluminate, and chlorinated coppers, which react with the water to form insoluble hydroxides. These hydroxides precipitate with the coalesced colloids as agglomerated flocs. Certain polyelectrolytes are also capable of destabilizing the colloids and forming a dense floc.

The term "flocculating aid" has often been applied to other materials which when used in conjunction with the primary coagulants often increase the density and settling velocity of the agglomerated floc. The most common materials used as flocculating aids include clays, activated silica, and polyelectrolytes.

The principal advantage of coagulation is that the destabilization of the colloids facilitates their removal by conventional sedimentation or filtration processes. In sedimentation, the coagulated particles agglomerate into floc particles, thereby, improving removal efficiency. In filtration, the destabilization of the colloids increases the particle sizes and the particle interactions with the filter and results in an improvement in the solids capture efficiency.

8.3 REMOVAL OF HARDNESS

As noted in Section 7, hardness is normally defined as the concentration of calcium and magnesium ions in the water. These elements are of concern in circulating cooling water systems because they are the major source of scale. The removal of these ions is usually accomplished through chemical reaction and subsequent precipitation and sedimentation of insoluble calcium and magnesium compounds or by ion exchange. The term "softening" has been universally applied to the processes for hardness removal.

8.3.1 Cold Lime-Soda Process

The cold lime-soda process is one of the most widely used processes for water softening. In this process, lime ($Ca(OH)_2$) and soda ash (Na_2CO_3) are added to water in sufficient quantities at ambient temperatures to convert all the calcium to calcium carbonate and all the magnesium to magnesium hydroxide. Both carbonate hardness (soluble calcium and magnesium bicarbonates) and non-carbonate hardness (calcium and magnesium sulfates) are removed by the cold lime process reactions. The resulting calcium carbonate and magnesium hydroxide precipitates are removed by conventional sedimentation processes, such as circular clarifiers. The process can reduce the calcium hardness to approximately 35 mg/l (expressed as $CaCO_3$) and magnesium hardness to approximately 33 mg/l (expressed as $CaCO_3$) due to the solubility of these compounds at ambient temperatures and the incomplete reaction within the limited contact time(2). Thus, the total hardness from a cold lime-soda softening process may not be expected to run much below 68 mg/l (expressed as $CaCO_3$)(2). The pH after cold lime-soda softening typically will range from 9 to 10.5. Any excess lime remaining in solution after the lime-soda treatment may tend to precipitate later in the system. As a safeguard, water softened by the cold lime-soda process is often treated with carbon dioxide or acids to neutralize the excess lime to soluble calcium bicarbonate.

8.3.2 Hot Lime-Soda Process

The hot lime-soda process is similar to the cold lime-soda process except the reactions occur at elevated temperatures. The effects of the elevated temperatures are to reduce the solubility of precipitates, $CaCO_3$ and $Mg(OH)_2$, increase the reaction rates, and improve the settling properties of the precipitates. The chemical requirements are also reduced since free carbon dioxide is driven off by the heating process, alleviating the need for converting carbon dioxide to calcium carbonate via lime addition. In hot lime-soda softening, steam is usually mixed with the raw water to raise the temperature to about 212°F. Packaged softening reactors, in which the steam injection and settling tanks are combined into an integral unit, are commonly used. Filters are also used downstream of the settling tanks to improve capture of the calcium and magnesium precipitates.

Total residual hardness values of less than 25 mg/l are typical with the hot lime-soda process.

8.3.3 Warm Lime-Soda Process

Since elevations in temperature can improve the softening process, the effectiveness of the warm lime-soda softening process can be considered to fall between that of the cold and hot lime-soda process. While warm processes are not common, they may find particular application in recirculating water systems where the recirculating water temperature leaving the condenser is in the range of 80 to 120°F (27 to 49°C)(4).

8.3.4 Ion Exchange

Water can also be softened by passing the water through cation ion exchange resins where the calcium and magnesium ions are replaced with sodium ions. The sodium ions form soluble products with the anions present in the cooling water, thereby, eliminating scale formation. The resins must be regenerated with a solution of sodium chloride to replace the calcium and magnesium ions with sodium ions. While ion exchange softening has been used extensively by the power industry for softening boiler feedwater, it has rarely been applied to circulating cooling water. Since the purpose of this section is to discuss only current or near horizon technologies, further discussion of ion exchange resins is deferred to Section 10.

8.4 USE OF CHEMICAL ADDITIVES

The use of chemical additives for water treatment in closed-cycle cooling water systems has been widely practiced in the power industry. This has primarily resulted from the simplicity of operation, flexibility, and low capital expenditures associated with this form of water treatment. Chemical additives have been employed for diverse water-related problems including pH control, scaling control, corrosion inhibition, biological fouling control, and protection against wood deterioration. Table 8.1 provides a comprehensive list of chemicals used in nuclear power plants(5).

8.4.1 pH Control

The control of the pH of the circulating water was probably one of the earliest applications of chemicals in the power industry. As noted in the previous section, the pH of the circulating water can be used to control its corrosive or scaling tendencies, using the Langelier or Ryznar Stability Indices as guidelines. If the pH of the cooling water is too high, sulfuric acid is usually used to lower the pH to acceptable levels. Sulfuric acid is usually the acid of choice because of its relatively low cost. In some instances hydrochloric acid may be substituted for sulfuric acid, if the sulfate concentration is high and additional increases may limit the cycles of concentration. If the pH is too low, lime or caustic soda can be used to raise the pH.

8.4.2 Corrosion Inhibitors

Corrosion inhibiting chemicals usually protect the metal surfaces from corrosion by forming protective films on the metal surface. The operation of circulating cooling water systems at slightly scaling conditions to form protective films of calcium carbonate has already been explained in Section 7. Most chemical inhibitors can be classified as either anodic or cathodic, depending on whether their films are formed at the anode or cathode of the galvanic corrosion cell. The calcium carbonate method of corrosion protection discussed in Section 7 can be considered a cathodic type of corrosion inhibitor. Other types of cathodic inhibitors include polyphosphates, silicates, zinc, nickel, lead, and copper. The metals react with the anions in the circulating water to form insoluble deposits of hydroxides, carbonates or oxides at the cathodic areas of the corrosion cells. The polyphosphates and silicates act by providing anions to combine with the metal cations to form insoluble deposits at the cathodic area.

The anodic inhibitors consist of negatively charged radicals which cause metallic oxides to form at the anodic areas. The most common type of anodic inhibitors include the chromates, nitrates, ferrocyanides, orthophosphates, and organics.

Many chemical additive systems for corrosion control employ a combination of anodic and cathodic inhibitors to reduce the total chemical requirements. For example, when using chromates alone, concentration of up to 100 mg/l may be required(6). By combining the chromates with another anodic inhibitor, such as orthophosphate, the required chromate concentration may be reduced to 50 mg/l. The addition of a cathodic inhibitor, such as zinc, can further reduce the required chromate concentration to less than 10 mg/l. This particular combination of anodic and cathodic inhibitors is commonly called the Zinc Dianodic Method (7).

The organic inhibitors consist of a variety of organic compounds which include starch derivatives, lignosulfonates, tannins, gluconates, glyceride derivatives, and a variety of proprietary formulations. Many of the organic formulations have been developed to eliminate the need for the more toxic inorganic chromate methods. Organic-based corrosion inhibitors function by promoting the development of a protective metal oxide film or by creating a surface active barrier(8). Many organic inhibitors have been specifically developed to protect specific metals. In general, many of the organic-based lignin derivatives and organic sulfur inhibitors are not compatible with oxidizing biocides, such as chlorine.

8.4.3 Scaling Inhibitors

Scaling inhibitors consist of chemicals which tend to prevent the formation of hard scale by interfering with the precipitation process. Most scaling inhibitors fall into the general classifications of chelating agents, antinucleating agents, flocculants, and dispersants. The concentrations of these chemicals can vary from a few to several hundred parts per million depending on the quality of the recirculating water and the types of inhibitors used.

Chelating agents react with the metal ions to form a soluble, heat-stable complex. These complexes can be extremely resistant to precipitation and can persist at high concentrations(8). Some of the more common types of chelating agents include EDTA (ethylenediamine tetracetic acid), NTR (trisodium nitrilotriacetic acid), citric acid, and gluconic acids.

Antinucleating agents prevent crystal growth by disturbing the symmetry of the crystal structure and allow chemical compounds to remain in solution in a supersaturated state(9). Dispersants keep scale particulates in suspension and prevent agglomeration. Flocculants work in the opposite way by encouraging agglomeration, but in a controlled manner, producing a loose fluffy precipitate which does not adhere readily to metal surfaces. Polyphosphates, tannins, lignins, starches, polyacrylates, seaweed derivatives, and other organic formulations are antinucleating, flocculating, and dispersing agents.

Table 8.2 lists a compilation of some of the more common chemicals used for both scale and corrosion control(1).

8.4.4 Biological Fouling Control

Biological fouling control can be accomplished by either the use of biocidal chemicals to kill or inhibit biological growth or by the mechanical cleaning of the metal surfaces. Since the condenser tubes are the most susceptible part of the cooling system, automatic mechanical condenser cleaning methods have been developed and are discussed in Section 8.5. This section is limited to discussing the use of chemical additives for biofouling control.

In the United States chlorine has been the most widely used biocide in circulating cooling water systems. Chlorine is a strong oxidant which forms hypochlorous acid and hydrochloric acid when dissolved in water according to the following reaction:

$$Cl_2 + H_2O \rightleftharpoons HCl + HOCl$$

The hypochlorous acid under most conditions will further disassociate into a hydrogen and hypochlorite ion.

$$HOCl \rightleftharpoons H^+ + OCl^-$$

In sufficient concentration, both the hypochlorite ion and hypochlorous acid are strong biocides. They diffuse through the cell walls and oxidize protein groups, resulting in the loss of enzyme activity(10).

When chlorine is added to a water containing ammonia compounds, it reacts with the ammonia and organic nitrogen present to form mono-, dichloro-, and trichloramines. The chloramines are not as effective a biocide as chlorine and predominate at low pH values. If a sufficient quantity of chlorine is added, the chloramine can be completely oxidized to nitrogen gas, allowing the free hypochlorous acid to exist in the disassociated hypochlorite form. This quanity of chlorine which exists in the hypochlorous acid or disassociated hypochlorite form is defined as the free chlorine residual. The chlorinated ammonia forms, such as mono-, dichloro-, and trichloramines, make up the combined residuals. Together the free and combined residuals make up the total chlorine residual present in the cooling water. The term break-point chlorination has been used to describe operations in the range where the ammonia has been oxidized to nitrogen gas and a free chlorine residual exists.

The popularity of chlorination for control of biofouling in the power industry is primarily a result of its low cost, simplicity of implementation, availability, effectiveness, and extensive operating experience. Chlorination is usually accomplished by the direct injection of gaseous chlorine into the circulating water. Chlorination can be practiced as either a continuous, intermittent or shock treatment procedure. In continuous treatment, combined chlorine residuals are usually kept at around 0.3 to 0.5 mg/l(5). Continuous residuals in excess of 0.5 should be avoided to prevent deterioration of the construction materials in the cooling system(7). In many plants semi-continuous chlorination is practiced several times a day. In this form of chlorination, the combined residual in the water returning to the cooling tower after treatment is usually raised to about 0.5 mg/l after each treatment(5). For infrequent shock treatment, free residuals of several parts per million may be employed(10). The frequency of shock treatments may vary from

3 to 7 days(9).

As noted in Section 7, EPA effluent limitations place restrictions on the free available chlorine residual allowed in cooling tower blowdown. These limitations restrict free and combined residual chlorine values to no more than 0.2 mg/l. In instances where it is necessary to chlorinate beyond these levels to control biological fouling, it may be necessary to dechlorinate the effluent with a reducing agent, such as sulfur dioxide, prior to discharge in the blowdown.

While chlorine has been the most widely used biocide for the control of biological fouling in closed-cycle cooling systems, many other commercial biocidal chemicals are available. Table 8.3 provides a partial listing of some proprietary chemical formulations used for biological fouling control and some of their active ingredients(5). Most of these chemical biocides can be classified as either oxidizing or non-oxidizing biocides. The oxidizing biocides act in a way similar to chlorine by oxidizing cell protein. Some of the most common oxidizing biocides include chlorine dioxide, potassium permanganate, bromine, ozone, bromine chloride, and brominated propionamides. While the mechanisms of the oxidizing biocides are similar, they differ in regard to relative toxicity and cost. In the past, none of the other oxidizing biocides have been able to compete with chlorine with regard to cost. The brominated propionamides represent a rather recent addition to the family of oxidizing biocides and are of particular interest since they can be readily decomposed and detoxified by simply raising the temperature and pH(10).

The non-oxidizing biocides act by a variety of mechanisms which include affecting cell permeability, destruction of protein groups, precipitation of protein, etc. Some of the more common non-oxidizing biocides include the chlorinated phenolics, organo-tin compounds, organo-sulfur compounds, quaternary ammonium salts, methylene bio-thiocyanate, copper salts, thiocyanates, organic amines, arsenates and arsenites, acrolein, and cationic surface active agents. A detailed discussion of the mechanisms, dosages, economics, advantages, and disadvantages of each of these compounds is beyond the scope of this study. It is sufficient to say that as a family, the non-oxidizing biocides generally do not degrade rapidly by reaction with the chemical constituents in the water and, therefore, are concentrated in the circulating water systems. They can be used alone or in conjunction with an oxidizing biocide, such as chlorine, to afford broader control of biological growths. Although their toxicities vary, their resistance to decomposition may pose potential toxicity problems in direct discharge of cooling tower blowdown to receiving waters. EPA is developing effluent standards for toxic chemicals, and some of the non-oxidizing biocides may fall under these toxic chemical regulations.

8.4.5 Protection Against Deterioration of Cooling Tower Components

The application of chemical additives for the prevention of cooling tower deterioration is primarily limited to the wooden components which are subject to biological attack. Both the flooded sections of the tower and the non-flooded sections, which experience alternating wet and dry conditions, can provide suitable conditions for microbial growth. Generally, control of biological deterioration of wood in cooling towers is accomplished through pre-treatment of the wood before construction and the addition of chemical biocides to the circulating water.

Many of the chemical biocides discussed in the previous section for bio-fouling control are also effective in controlling wood deterioration in the flooded sections of the tower. However, since the non-flooded sections are not continuously in contact with the circulating cooling water, the pre-treatment of the wood prior to construction is the primary method of control for these areas.

Some of the most common types of wood preservatives used in cooling tower installations are listed in Table 8.4(7). It is of interest to note that almost all the chemicals used for the pre-treatment of wood used in cooling tower construction are on EPA's list of potential toxic substances. To the extent that these substances leach into the cooling water and enter the blowdown discharge, they may also result in the imposition of additional blowdown discharge limitations.

In some instances sulfuric acid is added to the cooling tower circulating water to prevent alkalinity buildup. This buildup would result in delignification of the wooden components of a cooling tower which in turn could lead to premature component failure.

8.5 MECHANICAL METHODS FOR FOULING CONTROL

As an alternative to the use of chemicals for control of biological fouling, automatic mechanical cleaning methods have been developed to remove scale and slime buildup in condenser tubes. Two commercially available automatic mechanical systems are the Amertap System and the American M.A.N. System(5).

In the Amertap System sponge rubber balls are recirculated with the cooling water through the condenser tubes. The balls are sized somewhat larger than the inside diameter of the condenser tubes to provide a cleaning action when forced through the condenser tube by the pressure differential. Sponge rubber balls with abrasive bands are also available to provide additional scouring action for more tenacious scale or fouling deposits. A separate ball collection strainer is provided in the outlet pipes so that the balls can be recaptured and continuously recycled and injected into the condenser inlet. The balls have a specific gravity close to the cooling water to ensure equal distribution throughout the condenser tube bundle. The Amertap System can be operated in either a continuous or intermittent mode. About 20 percent of the tubes have these balls passing through them at a given time.

The American M.A.N. System, which was developed in Germany and only recently introduced in the United States, uses a system of brushes and baskets to provide automatic condenser tube cleaning. Each condenser tube must be fitted with its own internal plastic brush and plastic cages located at each end of each condenser tube. Through a system of valving, cleaning is initiated by reversing the direction of flow in the condenser tubes. Each time the flow is reversed, the brush is driven from one end of the condenser tube to the other. A complete cycle, which normally takes less than 80 seconds, consists of two flow reversals and two passes of the brush for restoring the flow to its original direction.

While mechanical cleaning may reduce the need for biocide addition in many applications, chlorination is still often practiced to control biological fouling and wood deterioration in the cooling tower. In addition, problems in clogging of the strainers, ball clogging in the condenser, and general maintenance have plagued some mechanical cleaning installations.

8.6 SLUDGE PROCESSING

Since environmental regulations and pressures may restrict the discharge of concentrated sludge and residues resulting from water treatment processes, such as sedimentation, softening, etc., some of the unit processes available for sludge processing are briefly described. In general, the objective of sludge processing is to concentrate the solids further and convert them from a liquid to a solid form to facilitate handling and ultimate disposal. The unit processes of interest for sludge treatment can be loosely classified as thickening and dewatering.

8.6.1 Thickening

Thickening is defined as the increase in the concentration of the solids in a sludge by the removal of a portion of the liquid in which the solids are suspended. The purpose of thickening is to reduce the total volume of sludge to improve the efficiency of subsequent treatment processes. A solids concentration of anywhere from 3 to 10 percent is typical of that attained from a thickening operation. Sludge thickening is normally accomplished by one of three methods. The most common methods used for sludge thickening are gravity thickening, air flotation thickening, and centrifuge thickening.

In gravity thickening the sludge is gently agitated to enhance the compaction of the solids and to cause the release of trapped water from the concentrated solids. Gravity thickening is essentially an extension of the basic sedimentation process to the hindered settling zone, where particle settling velocities are affected by particle interactions and solids concentration. Gravity thickening is normally performed in circular tanks, similar in many ways to circular clarifiers. However, the tanks are equipped with picket type rakes, which move at reduced velocities to provide the necessary slow agitation.

In dissolved air flotation thickening, air is dissolved in the sludge by contacting the sludge with air at elevated pressures. The sludge is then placed in open tanks where fine air bubbles are formed as the air comes out of solution. These bubbles adhere to the sludge particles, thereby increasing their buoyancy, and cause the solids to float to the surface. At the surface the floating sludge is collected through a skimming system. Chemicals are often employed in air flotation to aid in particle agglomeration.

Centrifuges have also been used for thickening of some sludges. However, these applications have been limited primarily because of the high maintenance and power cost associated with centrifuge thickening as compared to gravity and air flotation thickening. Centrifuges are, therefore, more frequently used for sludge dewatering to solids concentrations in excess of those normally associated with thickening.

8.6.2 Dewatering

Dewatering, as used in this section, is used to define those processes which remove a sufficient quantity of water from the sludge to change it from a free flowing liquid to a semisolid form. Dewatering processes, therefore, normally produce an end product of at least 10 percent solids and upwards to 95 percent solids in the case of evaporative drying beds. Many of the dewatering processes incorporate the addition of chemicals, such as lime, ferric chloride, alum or polyelectrolytes, to improve the sludge dewaterability. The most common types of dewatering processes include evaporation ponds or drying beds, vacuum filters, centrifuges, horizontal belt filters, and filter presses.

Evaporation ponds or drying beds have been widely used by the power industry in the Western United States for disposal of cooling tower blowdown and other waste streams. In evaporation ponds, the sludges are placed in open ponds. As the water evaporates, the solids continue to concentrate until they reach a dried state. Many evaporation ponds have been lined with impermeable liners to prevent leaching of dissolved contaminants into the ground water. Since drying beds can only be effective in areas where the evaporation exceeds the net precipitation, their use is usually limited to the more arid parts of the United States.

Vacuum filters reduce the moisture content of sludge by applying suction to the underside of filter media attached to a rotating drum. The drum is partially immersed in the liquid sludge, so that as it rotates, a solid cake is formed on the filter. The vacuum is released at a point in the drum's rotation, and the cake is scraped off before the filter is re-immersed in the liquid sludge.

Horizontal belt filters are similar to vacuum filters except that roller pressure is used instead of a vacuum to force the water from the sludge. The most common type of belt filters employ two parallel belts which sandwich the liquid sludge between them. A system of rollers is used to apply pressure to the sludge layer squeezed between the belts, thereby dewatering the sludge as the water is forced through the belts.

Centrifuges rely on centrifugal force to achieve a high rate of separation between solid and liquid fractions. Continuously rotating solid bowl centrifuges are the most common type employed for sludge dewatering. Sludge is introduced at one end of the rotating bowl. As the centrifuge spins, the solids are thrown to the periphery of the bowl where they are continuously conveyed to the outlet via a screw mechanism.

Vacuum filters, horizontal belt filters, and centrifuges are usually capable of producing solids concentrations varying from 15 to 30 percent solids. If a drier sludge is desired, filter presses which operate on a similar principle to belt filters, except at higher pressures, are employed. In order to achieve the high pressure, filter presses must be operated in a batch process. The filter press itself usually consists of several vertical plates attached to a rigid frame. Liquid sludge is initially loaded in the spaces between the filter plates and compressed at high pressures to produce the desired solids concentration. The liquid passes through the filter surface and exits through drainage ports. When the cycle is complete, the plates are separated allowing the dry cake to drop from the frame. Solids concentrations as high as 50 to 60 percent solids can be obtained in some filter press operations.

TABLE 8.1. LIST OF CHEMICALS ASSOCIATED WITH NUCLEAR POWER PLANTS(5)

A. CORROSION & SCALE INHIBITORS

Chromates

Sodium chromate
Sodium dichromate
Zinc chromate
Zinc dichromate
Potassium chromate
Potassium dichromate

Phosphates and Polyphosphates

Calcium metaphosphate
Sodium phosphate
Sodium metaphosphate
Sodium hexametaphosphate
Sodium tripolyphosphate
Sodium pyrophosphate
Zinc phosphate
Sodium orthophosphate
Calcium phosphate
Organic polyphosphates

Glassy Silicates

Sodium silicate

Nitrites and Nitrates

Sodium nitrite
Sodium nitrate
Potassium nitrate

Cyanates

Sodium ferrocyanate

Fluorides

Sodium fluoride

Amines (also used as biocides)

Octadecylamine
Ethylenediamine
Cyclohexylamine
Benzylamine

Chelating Agents

Ethylenediamine Tetracetic acid (EDTA)
Nitrilotriacetic acid (NTA)
LTSR - "low temperature scale remover" (a proprietary compound produced by Dow Chemical)

B. CLEANING & NEUTRALIZING COMPOUNDS

Alkaline Cleaning Stage

Sodium hydroxide
Calcium hydroxide
Sodium phosphate
Sodium sulfate
Sodium triphosphate
Ammonium hydroxide

Acid Cleaning Stage

Citric acid
Sulfuric acid

Neutralizing (Passivating Stage)

Sodium carbonate
Sodium sulfate
Sodium phosphate

(continued)

TABLE 8.1 (continued)

B. CLEANING & NEUTRALIZING COMPOUNDS (continued)

Neutralizing (Passivating) Stage (continued)

Sodium diphosphate
Sulfuric acid
Lithium hydroxide
Morpholine
Sodium lignosulfonate
Cyclohexylamine
Ammonium sulfate
Ammonium hydroxide
Ammonia

Oxygen Reducers

Hydrazine
Morpholine
Sodium sulfite
Cobalt sulfate

Reactivity Control

Boric acid

C. BIOCIDES (Cooling Tower Use)

Oxidizing Biocides

Chlorine
Bromine
Sodium hypochlorite
Calcium hypochlorite
Potassium permanganate
Chlorinated cyanurates and inocyanurates

Persulfate Compounds

Potassium hydrogen persulfate

Non-oxidizing Biocides

1. Chlorinated and/or phenylated phenols:
    - Chloro-O-phenylphenol
    - 2-Tert-Butyl-4-chloro-5-methylphenol
    - O-Benzyl-p-chlorophenol
    - 4,6-Dichlorophenol
    - 2,4-Dinitrochlorobenzene
    - 2,6-Dinitrochlorobenzene
    - 2,4,5-Trichlorophenol
    - 1,3-Dichloro-5,5-Dimethylhydranotin
    - Trichloromethyl sulfone (Bis)

    Sodium salts (ates) of:
    - O-Phenylphenol
    - 2,4,5-Trichlorophenol (sodium 2,4,5-Trichlorophenate)

(continued)

TABLE 8.1 (continued)

C. BIOCIDES (continued)

    Chloro-2,phenylphenol
    2-Chloro-4-phenylphenol
    2-Bromo-4-phenylphenol
    2,3,4,6-Tetrachlorophenol
    Pentachlorophenol
  Potassium salts (ates) of:
    2,4,5-Trichlorophenol

2. Quaternary Amines (quaternary ammonium compounds)
    - Dilauryl dimethyl ammonium chloride
    - Dilauryl dimethyl ammonium oleate
    - Dodecyl trimethyl ammonium chloride
    - Trimethyl ammonium chloride
    - Octadecyl trimethyl ammonium chloride
    - N-Alkyl benzyl-N,N,N-trimethyl ammonium chloride
    - Alkyl-9-methyl benzyl ammonium chloride
    - Lactory mercuriphenyl ammonium lactate
    - Alkyl dimethyl benzyl ammonium chloride
    - 3,4-Dichloro benzyl ammonium chloride
    - Phenylmercuric trihydroxythyl ammonium lactate
    - Phenylmercuric triethanol ammonium lactate
    - Alkyl (C_{12} to C_{18}) dimethyl benzyl ammonium chlorides
    - 1-Alkyl (C_6 to C_{18}) amino-3 aminopropane monacetate

3. Organo-metallic Compounds
  Organotins
    Bis (tributyl tin) oxide
  Organosulfurs
  Disulfides
  Organothiocyanates
  Methylene bisthiocyanate

4. Cationic Surface Active Agents
    - Sulfonium
    - Phosphonium
    - Arsonium
    - Iodonium

5. Dithiocarbamic Acid Salts
    - Sodium dimethyl diethyl dithiocarbamate
    - Disodium ethylene bisdithiocarbamate

6. Organic Amines (often used with Pentachlorophenol)
    - Primary Rosin Amines
        - Sodium carboxethyl rosin amine
        - Rosin amine acetate

(continued)

TABLE 8.1 (continued)

C. BIOCIDES (continued)

Non-oxidizing Biocides (continued)

6. Organic Amines (continued)
   - Other Amine (primary beta-amines and beta-diamines)
     - Chloramine
     - Benzylamine
     - Cyclohexylamine
     - Ethylenediamine
     - Polyethyleneamine
   - Zinc and Copper Salts
     - Zinc sulfate
     - Copper sulfate
     - Copper citrate
   - Acrolein
   - Arsenates
   - Arsenic Acid
   - Sodium arsenite
   - Copper ions
   - Zinc ions

Inorganic Scale and Precipitates

- Calcium carbonate
- Calcium phosphate
- Calcium sulfate
- Calcium hydroxide
- Magnesium carbonate
- Magnesium hydroxide
- Magnesium phosphate
- Iron oxides

TABLE 8.2. COMMON CHEMICAL ADDITIVES FOR CORROSION AND SCALING CONTROL IN RECIRCULATING COOLING WATER SYSTEMS(10)

Acrylamide polymers and copolymers
Alkylphenoxpolyethoxyethanol
Benzotriazole
Diethylenetriaminepantakis(methylenephosphonic acid)
Dioctyl sodium sulfosuccinate
Disodium phosphate
Ethylenediaminetetraacetate
Ethylenediaminetetrakis(methylenephosphonic acid)
Hexamethylenediaminetetrakis(methylenephosphonic acid)
1-Hydroxyethylidene-1, 1-diphosphonic acid
Monobutyl esters of polyethylene and polypropylene glycols
Nitrilotri(methylenephosphonic acid)
Poly(amineepichlorohydrin) condensates
Poly(amineethylene dichloride) condensate
Polydimethyidiallylammonium chlorides
Polyethylenimine
Polylphosphate esters (low mol. wt.)
Polyoxpropyleneglycol
Sodium carboxymethylcellulose
Sodium citrate
Sodium dichromate
Sodium hexametaphosphate
Sodium lignosulfunates
Sodium mercaptobenzothiazole
Sodium molybdate
Sodium nitrate
Sodium nitrilotriacetate
Sodium nitrite
Sodium polyacrylate
Sodium polymethacrylate
Sodium polystyrenesulfonic acid and copolymer
Sodium silicates
Sodium tetraborate
Sodium tripolyphosphate
Sodium zinc polyphosphate
Styrene maleic anhydride copolymers
Sulfanic acid
Tannins
Tolytriazole
Zinc sulfate

TABLE 8.3. PARTIAL LISTING OF COMMERCIALLY AVAILABLE FORMULATIONS FOR MICROORGANISM CONTROL(5)

Chemical	Composition (%)	Usage
NALCO 21-S		Periodically, as needed, 25-400 ppm or continuously
Sodium pentachlorophenate	21.3	
Sodium 2,4,5-trichlorophenate	11.9	
Sodium salts of other chlorophenols	3.0	
Inert ingredients	63.8	
NALCO 25-L or NALCO 425-L		Weekly, 20-300 ppm
1-Alkyl (C_6 to C_{18})-amino-3-aminopropane propionate-copper acetate complex	15.0	
Isopropyl alcohol	30.0	
Copper expressed as metallic	0.55	
Inert ingredients	55.0	
NALCO 201		Periodically, as needed 300-400 ppm or 12-60 ppm continuously
Potassium pentachlorophenate	15.7	
Potassium 2,4,5-trichlorophenate	9.0	
Potassium salts of other chlorophenols	1.8	
Inert ingredients	70.3	
NALCO 202		5-200 ppm periodically or continuously
Methyl-1,2-dibromopropionate	29.7	
Inert ingredients	70.3	
NALCO 207		Weekly, 25-50 ppm
Methylene bisthiocyanate	10.0	
Inert ingredients	90.0	
NALCO 209		As needed, 50-100 ppm
1,3-Dichlor-5,5-dimethylhydantoin	25.0	
Inert ingredients	75.5	
NALCO 321		Weekly, 5-200 ppm
1-Alkyl (C_6 to C_{18}) amino-3-aminopropane monoacetate	20.0	
Isopropyl alcohol	30.0	
Inert ingredients	50.0	
NALCO 322		As needed, 10-200 ppm
1-Alkyl (C_6 to C_{18}) amino-3-aminopropane monoacetate	19.8	

(continued)

TABLE 8.3 (continued)

Chemical	Composition (%)	Usage
2,4,5-Trichlorophenol	9.5	
Isopropyl alcohol	27.0	
Inert ingredients	43.7	
NALCO 405		As needed, 100-200 ppm
3,4-Dinitrochlorobenzene	22.2	
2,6-Dinitrochlorobenzene	2.8	
Inert ingredients	75.0	
Betz A-9		
Sodium pentachlorophenate	24.7	
Sodium 2,4,5-trichlorophenate	9.1	
Sodium salts of other chlorophenates	2.9	
Sodium dimethyl dithiocarbamate	4.0	
N-Alkyl (C_{12} - 4%,C_{14} - 50%,C_{16} - 10%) dimethylbenzylammonium chloride	5.0	
Inert ingredients (including solubilizing and dispersing agents)	54.3	
Betz C-5		
1,3-Dichloro-5,5-dimethylhydrate	50	
Inert ingredients (including solubilizing and dispersing agents)	50	
Betz C-30		
Bis(trichloromethyl) sulfone	20.0	
Methylene bisthiocyanate	5.0	
Inert ingredients (including solubilizing and dispersing agents)	75.0	
Betz C-34		
Sodium dimethyl dithiocarbamate	15.0	
Nabum(disodium ethylene bisdithiocarbamate)	15.3	
Inert ingredients (including solubilizing and dispersing agents)	69.7	

(continued)

TABLE 8.3 (continued)

Chemical	Composition (%)	Usage
Betz J-12		
N-Alkyl (C_{12} - 5%, C_{14} - 60%, C_{16} - 30%, C_{18} - 5%) Dimethylbenzyl-ammonium chloride	24.0	
Bis(tributyl tin) oxide	5.0	
Inert ingredients (including solubilizing and dispersing agents)	71.0	
Betz F-14		
Sodium pentachlorophenate	20.0	
Sodium 2,4,5-trichlorophenate	7.5	
Sodium salts of chlorophenate	2.5	
Dehydrobutyl ammonium phenoxide	2.0	
Inert ingredients, including dispersants	68.0	

TABLE 8.4. WOOD PRESERVATIVES USED FOR PRETREATMENT OF WOOD IN COOLING TOWER INSTALLATIONS(7)

Celcure (Acid Copper Chromate)

Chemonite (Ammoniacal Copper Arsenite)

Chlorinated Paraffin

Copper Naphthenate

Creosote

Erdalith (Chromonated Copper Arsenate)

Flouride Chromate Arsenate Phenol

Pentachlorophenol

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SECTION 9

METHODS OF CLOSED-CYCLE COOLING WATER TREATMENT

9.1 CURRENT TREATMENT TECHNOLOGY

9.1.1 Survey of Current Practice

In 1974, a power plant survey was conducted to determine the current industry practices in the treatment of recirculating cooling water in the power industry and to collect information for determining the cycles of concentration at which the systems are operated(1). There were 74 responses with respect to closed systems from the 160 questionnaires that were sent. The breakdown of responses according to the type of recirculating cooling system was as follows:

Mechanical draft cooling towers	46
Natural draft cooling towers	4
Cooling ponds, cooling lakes, and spray ponds	24
Total recirculating systems	74

Of the plants reporting, 47 reported using water from surface sources only, 24 from wells (3 from both), and 3 from sewage plant effluent. Of the 47 using water from surface sources only, 37 provided some form of treatment. Every plant not using surface water reported some form of treatment. Table 9.1 summarizes the types of water treatment reported.

The most common form of treatment used in the power industry includes on-stream treatment of recirculating water and consists of acid or base addition for pH control and chlorination for control of biological fouling. Treatment of make-up water is usually limited to screening, which is sometimes followed by sedimentation. Blowdown is normally treated only to limit the chlorine residual to that currently permitted under EPA discharge limitations. Table 9.2 summarizes frequency and method of blowdown treatment as reported in the 1974 Survey. Economics dictate that these minimal treatment steps be applied where water supply is plentiful.

Across the country, plant chemists and engineers have indicated operations are generally trouble free. Some stations have experienced biological fouling problems in the circulating water system during the summer months. Usual practice involves chlorination once per day during the summer months and once every other day during the winter months. The frequency of chlorination varies with change in the chlorine demand of the raw water and other factors relating to local environmental conditions.

9.1.2 Current Treatment Objectives

Based on the nationwide survey, the cycles of concentration presently average about 3.7 cycles for recirculating cooling water systems(1).

As noted in Section 7, future recirculating systems may operate at as high a cycles of concentration as possible in order to minimize the make-up water requirement and blowdown rate. The use of high cycles of concentration in circulating water to reduce make-up requirements is important where water is scarce; reduction of blowdown is important where it is necessary to treat the blowdown prior to discharge to a receiving water body.

Despite the desirability of operating at high cycles of concentration under such conditions, there are upper limits at which it is possible or practical to operate. These limits have been described in detail in Section 7 and are necessary to control excessive amounts of corrosion, scaling, and fouling due to high concentrations of certain contaminants in the recirculating water. While the levels at which it is practical to operate can be raised by using make-up treatment, corrosion resistant materials, and scaling, corrosion and fouling inhibitors, there are still upper bounds to the permissible cycles of concentration.

9.1.3 Definition of Current Technology

Because of the wide range in water treatment practices used for closed-cycle cooling systems, it is necessary to arbitrarily make a distinction between current and near horizon technology. As defined in Section 8, current technology includes those water treatment methods in common practice in the power industry today. Based on the 1974 survey, current technology will be defined to include the following:

1. No treatment or only screening of make-up water

2. No treatment of blowdown

3. Addition of chemicals for pH, corrosion and scaling control and chlorination for control of biological fouling in recirculating water.

9.2 NEAR HORIZON TREATMENT TECHNOLOGY

Due to the large volume of water circulated in closed-cycle cooling systems, current practice for the most part has precluded pretreatment of make-up water for economic reasons. As water becomes scarce and environmental controls for discharge more stringent, near horizon technology (NHT) will be adopted as the next treatment stage by the steam-electric generating industry. The purpose of NHT is to obtain the maximum cycles of concentration in the circulating water, consistent with the control limits provided in Section 7 and, thereby, to reduce both water make-up and blowdown requirements. For this document, NHT will include proven unit processes which are in current use for large volumes of water and can be readily applied for treatment of make-up, blowdown, and recirculating water.

9.2.1 Make-up Treatment

Filtration and cold lime-soda softening have been chosen for near horizon treatment of make-up water. Although these processes have not yet been extensively applied to the treatment of cooling water by the utilities, they are proven techniques which have been used in industrial and municipal applications for many years. Descriptions of these processes can be found in Section 8.

Two hypothetical freshwater sources (Ohio River and Lake Erie) with different chemical constituency, Tables 9.3 and 9.4, are used to illustrate how filtration and cold lime-soda softening of make-up water can increase the cycles of concentration. The control limits presented in Table 7.4 were used to determine the maximum allowable cycles of concentration.

For these illustrations, a recirculating flow of 500,000 gpm was assumed to calculate make-up and blowdown. Evaporation and drift losses were assumed to be 2 percent and .003 percent of the recirculating flow, respectively. Blowdown and make-up quantities were calculated from the cycles of concentration, evaporation, and drift using the equations presented in Section 7. For both current and near horizon technology, addition of sulfuric acid to keep bicarbonate alkalinity at 50 mg/l in the recirculating water was assumed. The results of make-up water treatment are shown in Tables 9.5 and 9.6 for the Ohio River and Lake Erie waters, respectively.

Current technology was assumed to be coarse screening of the make-up. Three cycles of concentration were assumed to be indicative of typical operating practice, based on the survey results shown in Table 9.2. In both the Ohio River and Lake Erie cases, suspended solids became the limiting factor at three cycles of concentration. NHT was represented by filtration and the cold lime-soda processes. It was assumed that filtration reduced the suspended solids concentration in the filtrate to 5 mg/l without altering the rest of the water chemistry.

The quality of the filtered water and the effect of filtration on make-up flow requirements and on the allowable cycles of concentration are shown in Tables 9.5 and 9.6. As in the case of current technology, sulfuric acid addition was assumed for maintaining the bicarbonate alkalinity at 50 mg/l. For the case of the Ohio River water, the cycles of concentration were increased to 9 as a result of filtration. The limiting criterion for the Ohio River water at 9 cycles of concentration became the product of the calcium and sulfate concentrations, which reached 1.49×10^6 as compared to the 1.5×10^6 limitation. For the Lake Erie water, filtration of the make-up water permitted an increase to 13 cycles of concentration because of the lower initial sulfate concentration. For this case, the product of the magnesium and silicate concentrations approached the 35,000 limiting criterion.

The cold lime-soda softening process is capable of removing calcium and magnesium from the make-up water by reaction with lime and soda ash. Some silica is also removed with the resulting magnesium precipitate. A detailed description of the process is in Section 8. The chemical composition of lime-soda softened water and the net effect upon the allowable cycles of concentration are shown in Tables 9.5 and 9.6. Note that the sodium concentration is increased as a result of the soda ash addition.

In the case of the Ohio River water, the cold lime-soda softening increased the cycles of concentration to 12. At this level, the product of the magnesium and silicate concentrations became controlling.

For the Lake Erie water example, the maximum permissible cycles of concentration achievable with the cold lime-soda softening was 14. This is only a marginal improvement over the 13 cycles of concentration attained using filtration. For the Lake Erie water, the product of the magnesium and silicate concentrations was controlling for both filtration and cold lime-soda softening treatment of the make-up water.

The resulting reduction in blowdown and make-up quantities are also shown in Tables 9.5 and 9.6. For the Ohio River water, filtration reduces make-up and blowdown flows by approximately 25 percent and 75 percent, respectively, as compared to current technology. Cold lime-soda softening resulted in a reduction of 27 percent and 82 percent, respectively, for the make-up and blowdown flows.

For the Lake Erie water, filtration reduced make-up and blowdown rates by 28 percent and 84 percent, respectively, while cold lime softening resulted in respective reductions of 28 percent and 85 percent.

9.2.2 Circulating Water Treatment

The processes of sidestream filtration and warm lime-soda softening have been selected as examples of the application of near horizon technology for the sidestream treatment of the circulating water. Sidestream treatment consists of treating a portion of the circulating water and returning it to the cooling system. Byproduct streams, such as sludge or filter backwash, are not returned to the cooling system and must be replaced with additional make-up quantities. Sidestream treatment can be envisioned as the equivalent of a blowdown recovery process which recycles treated water to the circulating water system.

9.2.2.1 Warm Lime-Soda Process--

As discussed in Section 8, the warm lime-soda process relies on the increased water temperature at the exit of the condenser to accelerate the cold lime-soda process reactions. Typically, temperatures of 80 to 120°F (27 to 49°C) are attained in circulating cooling water systems, and experience has shown that these temperatures are almost as effective as the 200°F (93°C) temperature employed in the hot lime-soda process(2). In addition the silica removed per part of magnesium removed increases at high silica concentration. These factors make warm lime-soda treatment a very attractive near horizon treatment process for removing calcium and magnesium hardness and silica.

As an illustration of the potential of the warm lime-soda process, consider the Ohio River example discussed in Section 9.2.1 and the control limits given in Table 7.4 for high cycles of concentration. Assume that filtration is used for treatment of the make-up water. The warm lime-soda process will be used to control the concentration of silica below 150 mg/l and the solubility product of magnesium and silica will be held to less than 60,000. It was assumed that the warm lime-soda process is capable of reducing the silica concentration to 20 mg/l and the magnesium concentration to 80 mg/l as $CaCO_3$(3,4).

The amount of sidestream treatment will be adjusted to achieve operation at the desired cycles of concentration. The quantity of blowdown can be computed from Equation (7.4) as:

$$B = \frac{E}{C - 1} - D$$

For assumed operation at 30 cycles of concentration, an evaporation rate of 10,000 gpm and drift losses of 15 gpm,

$$B = \frac{10,000}{29} - 15 = 330 \text{ gpm}$$

The flow rate of the sidestream treatment required can be estimated on the basis of maintaining the silica level and the solubility product of magnesium and silica within prescribed limits. It will be assumed that the solubility product of magnesium and silica will be the controlling criterion. The required sidestream treatment flow and silica and magnesium concentrations in the recirculating water are computed from material balances, Equations (9.1) to (9.3), described below. In these equations the variables are defined as follows:

x = concentration of magnesium in circulating water (mg/l $CaCO_3$).

y = concentration of silica in circulating water (mg/l SiO_2).

z = sidestream treatment (gpm).

Solubility Product Limitation:

$$xy \leq 60,000 \qquad (9.1)$$

"Mg" Material Balance:

$$\text{Blowdown} = \text{Make-up} - \text{Sidestream Removal}$$
$$(330)(x) = (10,345)(44) - (z)(x - 80) \qquad (9.2)$$

where:

44 mg/l is the concentration of magnesium in the make-up water, and 80 mg/l is the concentration of magnesium to be maintained in the sidestream.

"Si" Material Balance:

$$\text{Blowdown} = \text{Make-up} - \text{Sidestream Removal}$$
$$(330)(y) = (10,345)(8.4) - (z)(y - 20) \qquad (9.3)$$

where:

8.4 mg/l is the concentration of silica in the make-up water; 20 mg/l is the concentration of silica to be maintained in the sidestream.

Solving Equations (9.1), (9.2), and (9.3) simultaneously,

x = 550 mg/l (Mg concentration as $CaCO_3$)

y = 110 mg/l (SiO_2 concentration)

z = 575 gpm (sidestream treatment flow)

It can be seen that the silica concentration and the magnesium-silica solubility product remain within limits. In order to maintain the calcium sulfate solubility product within limits, however, it may be necessary to use hydrochloric acid instead of sulfuric acid for alkalinity control to reduce sulfate accumulation.

In the example presented, warm lime-soda sidestream treatment of less than 0.5 percent of the make-up water flow can increase the cycles of concentration from 9 to 30. In both cases, filtration of the make-up water was assumed.

9.2.2.2 Sidestream Filtration--

In some cooling water systems, dust entrainment in the cooling tower can be a major source of suspended solids. It has been estimated that a normal industrial ambient atmosphere can add approximately 75 mg/l of suspended solids on a make-up flow basis(3). This added dust can cause suspended solids levels to approach the 400 mg/l limitation at only 5 cycles of concentration. Sidestream filtration can effectively control the suspended solids level to permit operation at higher cycles of concentration. While warm lime-soda softening can also remove suspended solids, filtration may be more economical, if silica or magnesium-silica levels are not controlling. In some cases, the combination of sidestream warm lime-soda softening (Subsection 9.2.2.1) followed by filtration may permit operation at very high cycles of concentration.

9.2.3 Blowdown Treatment

While most power plants discharge blowdown from circulating water directly into receiving waters, evaporation ponds are sometimes used in the arid regions of the United States. Evaporation ponds can provide a cost effective solution for blowdown disposal, if the cost of transporting the blowdown to an acceptable alternative surface water body is excessive and groundwater injection is prohibited. Because the cost of constructing an evaporation pond with an impermeable liner to prevent groundwater contamination is high, evaporation ponds often are operated in conjunction with make-up and sidestream treatment to minimize the blowdown volume and the size of the evaporation ponds.

As an example of an evaporation pond application, the water treatment system for the proposed Sundesert Nuclear Plant will be discussed(5). This station would utilize irrigation water high in dissolved solids as a source of make-up water. An analysis of this irrigation water is shown in Table 9.7.

To minimize the blowdown, the Sundesert Nuclear Plant is designed to employ clarification and partial softening of the make-up water and sidestream clarification and softening of the circulating water. Table 9.8 summarizes the effluent from each of the make-up and sidestream treatment processes(5). The parameters shown in Table 9.8 for the high cycles of concentration are within the suggested criteria shown in Table 7.4. A small amount of sulfuric acid is also added to the make-up stream to prevent calcium carbonate deposition. The sidestream clarifier operates in the 75 to 129°F (24 to 54°C) range, which is sufficient to enhance silica reduction. The cycles of concentration value computed from Equation (7.4) for this plant is 17.5. (Equation (7.4) does not account for blowdown of sludge from the sidestream clarifier.)

The cycles of concentration can also be estimated by comparing the ratio of the chloride concentration in the circulating water to that in the raw make-up water. The cycles of concentration computed using the chloride concentration is 17.3, which compares favorably with the 17.5 value given above.

9.2.4 Costs of Near Horizon Technology

The approximate cost for the types of treatment discussed in Section 9.2.1 and 9.2.2 is shown in Table 9.9. Capital costs, which affect the approximate installed value in 1978 dollars, were estimated from equipment costs assuming installation costs were 40 percent of the equipment costs. An additional 10 percent of equipment costs was assumed for electrical work and 35 percent for contingencies in developing the cost estimates. The cost of the evaporation pond is based on excavation and membrane liner costs for 200 acres of evaporation pond area.

Table 9.10 presents the assumed chemical consumption as estimated from the water quality analysis for each of the examples. Chemical costs are presented in Table 9.9 without and with the addition of ferric chloride to the clarifiers to improve the settling of solids. Chemical consumption for the irrigation waste water example was obtained from Reference 5.

No attempt was made to estimate labor requirements for operating and maintaining the water treatment system, power cost, and the cost for disposal of sludge.

The total annual costs presented in the last column of Table 9.9 were obtained by amortizing the capital cost over 20 years at 7 percent and adding the capital recovery costs to the chemical costs. The total annual cost figure includes the addition of ferric chloride in the water softening steps. Table 9.9 shows that filtration with sidestream warm lime-soda softening can be competitive with cold lime-soda softening of the make-up water in some cases.

9.3 SPECIALIZED CASES OF MAKE-UP WATER

A few power plants have utilized sea water or sewage treatment plant effluent as make-up water for circulating cooling water systems. Special problems or experiences reported from such plants are briefly summarized in this section.

9.3.1 Use of Brackish or Saline Water

In a 1977 draft report to EPA(6), Hittman Associates reported that there were five steam-electric generating plants in the United States, which utilized salt or brackish water as the source of make-up water. Of these, only the Atlantic City Electric Company's B. L. England Station is listed as a fully operational saltwater cooling tower system. Two of the stations are experimental. Two plants (Chalk Point, Potomac Electric Power Company; and Jack Watson, Mississippi Power Company) utilize brackish water as the make-up supply. The Delmarva Power Company's Vienna Station uses, as make-up, river water which is seasonably brackish.

A typical composition of sea water is given in Table 9.11. The composition of coastal and estuarine (brackish) waters vary. They generally contain less chlorides, but more bicarbonates, calcium, potassium, and silica than sea water. A brackish water is defined as any water containing between 3,000 and 20,000 mg/l total dissolved solids.

The primary effect of saline water is to increase the corrosion rate of metals within the cooling system. High salt concentrations can cause spalling of concrete and delamination of asbestos cement. Special construction materials, such as sulfate cement and silicon bronze or stainless steel hardware, are utilized in constructing saltwater cooling systems.

Icing problems, normally associated with freshwater cooling towers in cold climates, are reduced with the use of sea water. On the other hand, saltwater drift and spray are larger and can be detrimental to vegetation and equipment in the down-wind areas.

Atlantic City Electric's B. L. England Unit 3 (175 MWe), completed in 1974, utilizes sea water from Great Egg Harbor Bay as a source of make-up water. The bay water is tidal with an average of 30,000 mg/l total dissolved solids. The unit is cooled by a Reserach Cottrell natural draft hyperbolic, counterflow cooling tower. This is the first saltwater cooling tower designed and operated in the United States.

Approximately 65,000 gpm of sea water at 1.5 to 2 cycles of concentration are circulated to cool Unit 3. Approximately 3,000 gpm is blown down from the cooling tower and discharged into the circulating water intake system of the other two units, which operate with once-through cooling.

The saline make-up water receives no pretreatment other than screening. When Unit 3 went on line, sulfuric acid was added to the recirculating water to maintain a pH between 7.0 and 7.5 to control scaling. For the past two and a half years the acid feed has been discontinued, allowing the pH to naturally rise in the closed system to about 8.5. Theoretically, the recirculating water should be scale forming; however, no scale has been observed, perhaps due in part to an increase in solubility of $CaCO_3$ in saline water.

The cooling tower trays are asbestos cement filled with a concrete piping distribution system. The condenser tubes are 90-10 copper-nickel alloy. No unusual maintenance problems have been experienced.

The utility produces sodium hypochloride (NaOCl) from the sea water by electrolysis for disinfection. The cooling water is chlorinated downstream of the cooling tower in order to maintain a free chlorine residual of 0.5 mg/l in the recirculating water. The 3,000 gpm blowdown from Unit 3 mixes with the other discharges from Unit 3 and is discharged at the plant intake, thereby dissipating the chlorine residual held in the recirculating cooling water.

9.3.2 Use of Sewage Effluent

Some power plants have used municipal sewage effluents as a source of make-up water for cooling systems. This application is limited to those power plants located close to large municipal waste water treatment plants.

The quantity of effluent available from a municipal waste water treatment plant depends on the size of the population served, the variation in flow rates due to weather conditions, and water usage patterns. Typical waste water generation varies from 100 to 200 gallons per capita per day, depending on the extent of water conservation measures, infiltration, and inflow.

Total municipal waste water reuse by industries in 1974 was reported by the United States EPA to be 133 billion gallons per year based on use at 358 locations. Of this, approximately 20 percent was used by the power generation industry.

Table 9.12 presents a typical analysis for raw sewage and effluent from a secondary municipal waste water treatment plant. EPA has required that all municipal waste water treatment plants achieve at least secondary treatment by 1981. In secondary treatment, biochemical oxygen demand (BOD) is reduced by conversion of dissolved organics and carbohydrates to microbial mass during the activated sludge process. This microbial mass is then recaptured through secondary sedimentation.

In some instances, more advanced treatment is required to remove nitrogen and phosphorous or reduce suspended solids and BOD to very low levels. Some advanced treatment techniques, such as lime precipitation for phosphorous removal and filtration, approach near horizon technology for cooling system make-up. These treatment techniques supplement normal municipal treatment of effluents with chlorine or ozone prior to discharge to a receiving water body.

Treated waste water may be utilized as make-up for recirculating systems without further "polishing" in many instances. The treatment methods previously discussed, such as filtration and softening, are effective methods for further upgrading the water quality if required. Activated carbon beds may also be utilized to remove soluble refractory organics.

The waste water treatment plant for Colorado Springs currently provides tertiary effluent to the Martin Drake Power Plant(7). The Martin Drake Plant is located approximately two miles from the waste water treatment plant and is a 60-MWe coal burning plant. The power plant is equipped to use the tertiary effluent for either cooling tower make-up or ash sluicing.

The Colorado Springs tertiary plant has two circuits, each involving different processes. The industrial circuit has a capacity of 2.0 mgd, which is directly piped to the Martin Drake Power Plant. In the industrial treatment circuit, chlorinated secondary effluent is initially subjected to solids contact clarification using lime. The water is raised to a pH of 11.5 in this process, utilizing a lime dose of 300-350 mg/l. The high pH water leaving the solids contact unit is neutralized with carbon dioxide from recalcination and augmented with sulfuric acid as needed. After pH neutralization, the water is passed through a dual media anthracite and sand filter and a carbon adsorption tower.

The Southwestern Public Service Company has been utilizing secondary-treated domestic waste water effluent for reuse in cooling and boiler make-up at the Nichols Station Plant in Amarillo, Texas and the Jones Station in Lubbock, Texas(7). The treated effluent delivered to the Nichols and Jones Stations receives primary and secondary treatment and is chlorinated to 0.1 mg/l residual chlorine. Some problems with foaming, scaling, and biofouling were experienced, and it was found that treatment by cold lime-soda softening to a high pH value could mitigate most of these problems. At the Jones Station, filtration, reverse osmosis, and demineralization are used to further treat a small fraction of the waste water before its use as boiler make-up.

The Palo Verde Nuclear Generating Station of the Arizona Nuclear Power Project is designed to utilize treated waste water for cooling water make-up for each of its three 1,300-MWe units (7). Each cooling system has been designed to operate at 15-20 cycles of concentration. To operate at these relatively high cycles of concentration, the water quality parameters shown in Table 9.11 are maintained in the make-up water system.

An economic analysis of various alternative treatment systems as reported in Reference 6 indicated that biological nitrification, two-stage cold lime-soda softening, break-point chlorination, and dual-media filtration would provide the most cost effective treatment scheme.

TABLE 9.1. TYPE OF WATER TREATMENT ACCORDING TO EPA REGION AND TREATMENT CATEGORY(1)

	Plants by EPA Region								Total
Treatment Category	I	III	IV	V	VI	VII	VIII	IX	Plants
Softening and solids removal	0	1	1	1	2	0	1	1	7
Softening	0	0	0	1	2	0	1	1	5
Solids removal	0	1	1	0	0	0	1	0	3
pH adjustment	0	4	0	1	14	3	4	8	34
Acid applied	0	1	0	1	14	3	4	8	31
Base applied	0	3	0	0	0	0	0	0	3
Chemical additives	0	1	3	1	12	4	5	8	34
Corrosion inhibitor	0	1	2	0	11	3	4	7	28
Scale and fouling inhibitor	0	1	2	1	7	2	2	1	16
Total make-up and recirculating treatment	0	4	3	2	18	4	5	8	44

TABLE 9.2. RECIRCULATING SYSTEM PLANTS BY CYCLES OF CONCENTRATION RANGE AND TYPE OF BLOWDOWN TREATMENT(1)

	Plants by Cycles of Concentration Range						
	1 to 1.9	2 to 2.9	3 to 3.9	4 to 4.9	5 to 5.9	6 to 6.9	10 or Greater
Total recirculating plants for which cycles of concentration were calculated	9	7	9	11	4	2	2
Total plants with blowdown treatment	1	4	0	2	1	1	2
Solids removal	1	4	0	2	1	1	2
Sedimentation	1	4	0	2	1	1	1
Filtration	0	4	0	2	1	1	1
Evaporation	0	0	0	1	0	0	1
None	8	3	9	9	3	1	0

TABLE 9.3. ANALYSIS OF HYPOTHETICAL OHIO RIVER WATER

Calcium (Ca) as $CaCO_3$, mg/l	100
Magnesium (Mg) as $CaCO_3$, mg/l	44
Sodium (Na) as $CaCO_3$, mg/l	87
Chloride (Cl) as $CaCO_3$, mg/l	41
Sulfate (SO_4) as $CaCO_3$, mg/l	140
Bicarbonate (HCO_3) as $CaCO_3$, mg/l	50
Silica as SiO_2, mg/l	8.4
Suspended Solids, mg/l	90
pH	7.4

TABLE 9.4. ANALYSIS OF HYPOTHETICAL LAKE ERIE WATER

Calcium (Ca) as $CaCO_3$, mg/l	78
Magnesium (Mg) as $CaCO_3$, mg/l	34
Sodium (Na) as $CaCO_3$, mg/l	15
Chloride (Cl) as $CaCO_3$, mg/l	17
Sulfate (SO_4) as $CaCO_3$, mg/l	16
Bicarbonate (HCO_3) as $CaCO_3$, mg/l	94
Silica as SiO_2, mg/l	6
Suspended Solids, mg/l	100
pH	7.3

TABLE 9.5. EFFECT OF NEAR HORIZON TECHNOLOGY ON CYCLES OF CONCENTRATION HYPOTHETICAL OHIO RIVER WATER

	MAKE-UP WATER QUALITY AFTER TREATMENT			RECIRCULATING WATER QUALITY		
	Current** Technology	Filtration	Cold Lime-Soda Softening	Current** Technology	Filtration of Make-up	Cold Lime-Soda Softening of Make-up
Calcium (as $CaCO_3$) mg/l	100	100	35	234	$\boxed{900}$	420
Magnesium "	44	44	33	102	396	$\boxed{396}$
Sodium "	87	87	181	45	776	2172
Chloride "	41	41	41	51	369	492
Sulfate "	140	140	140	180	$\boxed{1665}$	2460
Bicarbonate "	50	50	68*	50	50	50*
Silica (as SiO_2) mg/l	8.4	8.4	7.5	18	75.6	$\boxed{90}$
Suspended Solids mg/l	90	5	10	$\boxed{300}$	45	120
Cycles of Concentration				3	9	12
Limiting Criteria				Suspended Solids 200 - 300	Calcium Sulfate $<1.5\times10^6$	Mg x SiO_2 $<35,000$
Blowdown Flow (gpm)				4485	1235	894
Make-up Flow (gpm)				15000	11250	10900

* Total alkalinity as $CaCO_3$
**Limited to coarse screening

TABLE 9.6. EFFECT OF NEAR HORIZON TECHNOLOGY ON CYCLES OF CONCENTRATION HYPOTHETICAL LAKE ERIE WATER

	MAKE-UP WATER QUALITY AFTER TREATMENT			RECIRCULATING WATER QUALITY		
	Current** Technology	Filtration	Cold Lime-Soda Softening	Current** Technology	Filtration of Make-up	Cold Lime-Soda Softening of Make-up
Calcium (as $CaCO_3$) mg/l	78	78	35	234	1014	490
Magnesium "	34	34	33	102	$\boxed{442}$	$\boxed{462}$
Sodium "	15	15	33	45	195	462
Chloride "	17	17	17	51	221	238
Sulfate "	16	16	16	180	$\boxed{1300}$	$\boxed{1134}$
Bicarbonate "	94	94	68*	50	50	50*
Silica (as SiO_2) mg/l	6	6	5	18	78	70
Suspended Solids	100	5	10	$\boxed{300}$	65	140
Cycles of Concentration				3	13	14
Limiting Criteria				Suspended Solids 200 - 300	Mg x SiO_2 35,000	Mg x SiO_2 35,000
Blowdown Flow (gpm)				4985	818	750
Make-up Flow (gpm)				15000	10833	10776

* Total alkalinity as $CaCO_3$

**Limited to coarse screening

TABLE 9.7. ANALYSIS OF IRRIGATION WASTEWATER FOR THE PROPOSED SUNDESERT NUCLEAR PLANT(5)

Calcium as $CaCO_3$ (mg/l)	398
Magnesium as $CaCO_3$ (mg/l)	184
Sodium as $CaCO_3$ (mg/l)	911
Chloride as $CaCO_3$ (mg/l)	599
Sulfate as $CaCO_3$ (mg/l)	645
Bicarbonate as $CaCO_3$ (mg/l)	262
Silica as SiO_2 (mg/l)	21
Suspended Solids (mg/l)	50
Total Dissolved Solids (mg/l)	2020
pH	8.0

TABLE 9.8. ANALYSIS OF WATER STREAMS FOR THE PROPOSED SUNDESERT NUCLEAR PLANT(5)

	Make-up	Circulating Water	Sidestream
Average Flow (gpm)	11,000	475,000	6,000
Calcium as $CaCO_3$ (mg/l)	197	351	37
Magnesium as $CaCO_3$ (mg/l)	168	344	82
Sodium as $CaCO_3$ (mg/l)	1,068	20,728	21,331
Chloride as $CaCO_3$ (mg/l)	694	10,356	10,375
Sulfate as $CaCO_3$ (mg/l)	730	11,284	11,284
Bicarbonate as $CaCO_3$ (mg/l)	33	43	35
Silica as SiO_2 (mg/l)	19	40	10
Suspended Solids (mg/l)	10	25	10
Total Dissolved Solids (mg/l)	1,895	28,240	28,305
pH	10.2	7.9	10.2

TABLE 9.9. COMPARISON OF TREATMENT COSTS FOR SELECTED EXAMPLES

Water Source	Type of Treatment	Treatment Flow (gpm)	Cyles of concen- tration	Equipment Cost ($1,000)	Installed Capital Cost ($1,000)	Chemical Costs[1] ($1,000/yr)	Total Annual Cost ($1,000/yr)
Lake Erie	No make-up treatment	15,000	3	-	-	55	55
	Filtration of make-up	11,250	13	1,100	2,287	52	268
	Cold lime softening of make-up	10,900	14	1,250	2,599	186.8 (138.3)[2]	432
	Sidestream softening and fil- tration of make-up	265 10,600	30	1,138	2,366	138.8 (132.4)[2]	357
Ohio River	No make-up treatment	15,000	3	-	-	127.8	128
	Filtration of make-up	10,800	9	1,000	2,079	109.5	305
	Cold lime softening of make-up	10,800	12	1,250	2,599	256.8 (209.3)[2]	502

(continued)

TABLE 9.9 (continued)

Water Source	Type of Treatment	Treatment Flow (gpm)	Cycles of concentration	Equipment Cost ($1,000)	Installed Capital Cost ($1,000)	Chemical Costs[1] ($1,000/yr)	Total Annual Cost ($1,000/yr)
	Sidestream softening and filtration of make-up	575 10,345	30	1,038	2,158	329.3 (326.6)[2]	533
Sun-desert Nuclear Plant Irrigation Waste Water	Partial softening of make-up	11,000	-	1,250	3,742	9,063	3,525
	Sidestream softening	6,000	17.5	550			
	Evaporation pond	682	-	-	24,000		

NOTES: 1. Chemical costs were: hydrated chemical lime (93%) at $35/ton, soda ash (99% Na_2CO_3) at $60/ton, sulfuric acid (100%) at $50/ton and ferric chloride (100%) at $5/100 lbs.

2. Items within parentheses denote chemical costs without ferric chloride addition to improve coagulation.

TABLE 9.10. ESTIMATED CHEMICAL CONSUMPTION FOR ALTERNATIVE TREATMENT TECHNOLOGIES FOR SELECTED EXAMPLES

Source of Water	Type of Treatment	Lime[(a)] (lbs/day)	Soda Ash[(b)] (lbs/day)	Sulfuric Acid[(c)] (lbs/day)	Ferric Chloride[(d)] (lbs/day)
Lake Erie	Acid addition for pH control			6,000	
	Filtration of make-up			5,700	
	Cold lime-soda softening of make-up	9,800		8,300	2,600
	Filtration of make-up and sidestream softening	1,700	6,100	6,000	75
Ohio River	Acid addition for pH control			14,000	
	Filtration of make-up			12,000	
	Cold lime-soda softening of make-up	6,200	8,500	8,400	2,600
	Filtration of make-up and sidestream softening	3,300	17,900	8,400	150

(continued)

TABLE 9.10 (continued)

Source of Water	Type of Treatment	Lime[a] (lbs/day)	Soda Ash[b] (lbs/day)	Sulfuric Acid[c] (lbs/day)	Ferric chloride[d] (lbs/day)
Sundesert Nuclear Plant Irrigation Waste Water	Partial softening of make-up and sidestream softening	50,000	48,000	5,000	4,300

NOTE:
(a) 93% hydrated lime
(b) 98% soda ash
(c) 98% sulfuric acid
(d) 20 mg/l dosage on 100% basis

TABLE 9.11. ANALYSES OF MAKE-UP WATER QUALITIES

Typical Sea Water Analysis		Make-up Waste Water Quality for Palo Verde Nuclear Generating Station (7)	
Sodium Chloride (mg/l)	27,000	Calcium as Ca (mg/l)	<28
Magnesium Chloride (mg/l)	3,200	Sulfate as SO_4 (mg/l)	<200
Magnesium Sulfate (mg/l)	2,200	Silica as SiO_2 (mg/l)	<10
Calcium Sulfate (mg/l)	1,200	Ammonia Nitrogen (mg/l)	< 5
Potassium Chloride (mg/l)	500	Total Phosphorous (mg/l)	<0.5
Calcium Bicarbonate (mg/l)	200	Suspended Solids (mg/l)	<10
Potassium Bromide (mg/l)	100	Biochemical Oxygen Deman (mg/l)	10
Total Salinity (mg/l)	34,000	Total Dissolved Solids (mg/l)	900
Total Alkalinity (mg/l)	115	pH	7.5-8.0
pH	8.0		

TABLE 9.12. TYPICAL WASTE WATER AND TREATMENT PLANT ANALYSES

Parameter	Raw Sewage Influent(8)	Primary Treatment Plant Effluent(7) (mean values)	Secondary Treatment Plant Effluent(7) (mean values)
Solids, total (mg/l)			
Dissolved, total	980	---	---
Volatile	260	---	---
Nonvolatile	720	---	---
Suspended, total	200	93	37
Volatile	160	---	---
Nonvolatile	40	---	---
BOD (mg/l)	200	167	28
TOC (mg/l)	200	142	35
COD (mg/l)	400	346	86
Nitrogen (mg/l)			
(total as N)	50	24	19
Organic	20	20	---
Free ammonia	30	---	11
Nitrates	0	---	---
Nitrites	0	---	---
Phosphorous (mg/l)			
(total as P)	5 - 20(9)	13	5
Heavy Metals (mg/l) (typical from Reference 10)			
Cadmium	8 - 142	14	50
Chromium	20 - 700	188	202
Nickel	2 - 880	165	165
Lead	50 -1270	156	67
Zinc	30 -8310	550	238
Mercury	.2 - 44	1	6
Manganese	---	176	144
Copper	20 -3360	191	92

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SECTION 10

FUTURE TECHNOLOGIES FOR CLOSED-CYCLE COOLING WATER TREATMENT

10.1 INTRODUCTION

Future technologies are defined as those processes which have not been applied to recirculating cooling water systems in power plants, but which may hold promise in solving water treatment problems in the future. These technologies are applicable for treatment of make-up water, circulating water, and blowdown. The established processes outlined herein are costly, but they provide either the ability to increase the number of cycles of concentration or advanced treatment of blowdown.

10.2 TREATMENT OF MAKE-UP WATER

The most likely candidates for the application of future technology to make-up waters are ion exchange resins for either water softening or complete demineralization.

10.2.1 Ion Exchange Softening

In the water softening application, the water is passed through a bed of ion exchange resin where the divalent and trivalent cations, such as calcium, magnesium, and iron, are removed from the water and replaced with sodium ions. The removal of the calcium and magnesium ions reduces the hardness and, consequently, the scale forming tendency of the water. The sodium forms extremely soluble salts with the bicarbonate, sulfate, and chloride ions, and even at high concentrations these salts do not result in scale formation.

The exchange medium is exhausted when most sodium ions have been replaced by divalent and trivalent cations. At this point, the resin must be regenerated by passing a concentrated solution of sodium chloride through the medium, which reverses the process as sodium ions replace the divalent and trivalent cations. In practice, the resin is never in a state of complete exhaustion or regeneration but functions effectively until small but appreciable quantities of hardness escape through the exchange medium.

Ion exchange softening can reduce the calcium and magnesium hardness to a few mg/l. The waste water produced during regen-

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eration contains naturally occurring hardness ions in solution with chloride plus excess sodium chloride. This waste water is relatively harmless to biota and may be permitted to be directly discharged to a receiving water body.

Ion exchange softening is more readily applicable to treating make-up flow, since the high concentrations of dissolved solids which occur in the recirculating water adversely affect the ion exchange equilibrium and leakage.

10.2.2 Ion Exchange Demineralization

In complete demineralization applications of ion exchange technology, all ions are removed and replaced with hydrogen and hydroxyl ions to produce a water comparable in quality to distilled water. The process is usually conducted in two steps. First, an acid-cation exchange resin replaces the cations in the water with hydrogen ions. In the second step, base-anion exchange, the exchange resin replaces the anion ions (such as bicarbonates, sulfates, and chlorides) with the hydroxyl ion. For complete demineralization, strong acid and strong base exchange resins are used.

Several variations of the basic demineralization approach have been developed using combinations of strong acid-weak base and weak acid-strong base exchange resins to achieve different degrees of cation and anion exchange. In some processes the acid and base exchange resins are contained in the same column. An economic evaluation must be made in each case to determine the best combination of exchange resins and procedures.

As an example of the application of a demineralization process to make-up water, consider the use of a carboxylic acid cation exchange resin for the removal of hardness (calcium and magnesium) and alkalinity. The metal cations (Ca^{++}, Mg^{++}, and Na^{+}) are absorbed by the carboxylic acid resin and exchanged for hydrogen ions. The released hydrogen ions further react with the bicarbonate ion (HCO_3^-) to form carbonic acid (H_2CO_3). Finally, the carbonic acid causes a shift in the bicarbonate equilibrium to produce carbon dioxide and water. The reactions for the process can be schematized as follows:

$$\text{Resin} \cdot \text{H} + \begin{bmatrix} Na^{+} \\ Ca^{++} \\ Mg^{++} \end{bmatrix} \longrightarrow \text{Resin} \begin{bmatrix} Na^{+} \\ Ca^{++} \\ Mg^{++} \end{bmatrix} + H^{+}$$

$$H^{+} + HCO_3^{-} \rightleftharpoons H_2CO_3$$

$$H_2CO_3 \rightleftharpoons H_2O + CO_2 \uparrow$$

While some forms of demineralization can tolerate high levels of dissolved solids, as in the case of ion exchange softening, the process is more applicable for treatment of make-up water. Demineralization wastes, however, may be more difficult to dispose than those which result from ion exchange softening since they contain excess acids and alkalis.

10.3 TREATMENT OF CIRCULATING WATER

The most likely candidates for the application of future technology to recirculating water are the use of membrane technology to control dissolved solids and the use of ozone to control biological fouling. One additional technology which may have some application potential is sidestream lime-barium softening.

10.3.1 Membrane Processes

The main application of membrane processes to recirculating cooling water systems is to control the concentration of dissolved solids by treating a portion of the recirculating flow (sidestream treatment). The two most common forms of membrane processes are reverse osmosis and electrodialysis. Both processses are subject to fouling by particulate matter when applied to streams containing even low concentrations of suspended solids.

In reverse osmosis, water moves across a semipermeable membrane from a region of high solute (dissolved salts) concentration to a region of lower solute concentration as a result of the application of a pressure gradient. In an application of reverse osmosis to circulating cooling water, a portion of the flow enters the concentrated side of the semipermeable membrane. The membrane permits desalinated water to pass through the membrane while rejecting dissolved salts, colloids, microorganisms, and particulates. The desalinated water is then returned to the circulating water system, while the concentrated salt stream is disposed. The most common types of reverse osmosis membranes commercially available are the tubular, spiral wound, and hollow fiber configurations. Cellulose acetate and polyamide are now the commonly used synthetic membranes. These membranes preferentially reject divalent ions, resulting in a 99 percent rejection efficiency for calcium, magnesium, and sulfate as compared to a 95 percent rejection efficiency for sodium and chloride(1).

One of the major problems facing reverse osmosis systems is that the membranes suffer from compaction with time(2). This results in a continual deterioration of flux rates and salt rejection efficiency, which are accelerated at high pressures. As a result, most manufacturers guarantee only a three-year life with a factorial reduction in operating flux.

During the last few years, several sea water reverse osmosis installations have been in service. These systems have operated without any acid or other chemical pretreatment and produce water with an average TDS content of 400 to 800 mg/l in a single stage (3). This amounts to about 98 percent removal of salts. Assuming the membranes resist deterioration, this technology appears adaptable for salt or brackish make-up supplies or sidestream treatment.

In electrodialysis, a combination of direct current and alternating cation and anion selective membranes are used to remove salts from water. The cation and anion membranes are stacked in an alternating array with electrodes at each end of the stack. The liquid passes between the membranes with the ions moving perpendicular to the membranes.

The electric currents induce a flow of anions and cations across the membranes. As a result of the process, the salinity of the water in half of the cells decreases, while it increases in the other half. The water in the cells with the reduced salinity can be returned to the cooling system, while the concentrated brine is either recirculated to the concentrated cells of the electrodialysis unit for another pass or discharged for disposal.

Unlike the reverse osmosis membranes, electrodialysis membranes preferentially transport divalent ions. The electrodialysis membranes also do not undergo compaction with time and have a longer life expectancy than do the reverse osmosis membranes. Although electrodialysis membranes are not sensitive to temperature, they are more sensitive to chlorine degradation than are reverse osmosis membranes.

10.3.2 Lime-Barium Softening

Barium hydroxide can be used in a sidestream precipitation process to reduce sulfate and silica levels in the circulating water. The barium hydroxide reacts with the sulfate present to form insoluble barium sulfate and two hydroxide ions.

$$Ba(OH)_2 + SO_4^{=} \longrightarrow BaSO_4 \downarrow + 2(OH^-)$$

In the presence of magnesium, magnesium hydroxide also precipitates, and silica is removed in an adsorption reaction with the magnesium hydroxide. The adsorption of silica with magnesium hydroxide will also occur during cold-lime-soda softening. Therefore, the main advantage of this process over cold lime-soda softening is the removal of sulfate ions. The process is more applicable for sidestream treatment than make-up treatment because of the high cost of barium hydroxide. The toxicity of barium compounds may also pose special disposal problems.

10.3.3 Use of Ozone to Control Biological Fouling

Ozone is receiving attention as an alternative to chlorine for many disinfection and biocidal applications, because it does not produce persistent residuals. As noted previously, chlorine reacts with ammonia and organic compounds to form chlorinated amines and hydrocarbons. Some of the chlorinated hydrocarbons have been found to be carcinogenic at fairly low concentrations. Ozone, on the other hand, is a strong oxidant (exhibiting approximately twice the oxidizing power of chlorine) which dissociates into oxygen without the production of such deleterious derivatives as chlorinated hydrocarbons. While ozone has been used widely in Europe, it has not been economically competitive with chlorination in the United States.

The testing of ozone as a biofouling control agent in saline waters was conducted by the United Stated Department of the Interior(4). In general, it was found that maintaining an ozone residual of approximately 1.0 mg/l was effective in controlling barnacles, algae, and slime. The results, however, suggest that continuous rather then intermittent ozonation may be necessary. Further testing is required to establish recommended dosage rates for non-marine applications and to protect metal components from ozone oxidation.

10.4 TREATMENT OF BLOWDOWN WATER

Presently, the regulatory guidelines specify limitations with respect to residual chlorine content for cooling water discharges. More strict standards will apply to "new sources," i.e., plants whose construction started after March, 1974. These stations will have to meet "no detectable amount" limitations with respect to chromium, zinc, and phosphorous as well as other corrosion inhibitors.

For power stations using recirculating evaporative cooling tower systems, blowdown from the tower is the largest volume of waste water produced by the station. As the cycles of concentration is increased through the utilization of pretreatment or sidestream processes, the blowdown volume will decrease. The concentration of constituents in the waste water, however, will increase by several fold, and the composition may change through the addition of inhibitors dictated by the higher cycles of concentration. Consequently, treatment employed for the blowdown will depend on the waste constituents present.

In the past, most power plants have discharged blowdown water directly into a receiving surface water body. In a few cases, sedimentation ponds have been used to reduce the suspended solids concentration prior to discharge. With the advent of more advanced treatment procedures for make-up and recirculating water, the concentration of dissolved constituents in the blowdown may be expected to increase. Future regulations may limit the discharge of concentrated blowdown streams into surface waters. As a result, more elaborate treatment processes for reducing the volume of the blowdown waste stream may be required.

Of major importance is the treatment of blowdown discharge when several waste water streams are combined. Effluent limitations for a plant which combines its waste water streams should not reflect pollutant reductions less than would be achieved if each stream were individually treated. In light of this, it should be noted that all power plant waste sources identified by EPA, other than cooling water, have suspended solids and pH limitations. Currently, oil and grease limitations are not applicable to rainfall runoff, and copper and iron limitations are included only for boiler blowdown and metal cleaning wastes.

If it is desired to combine all streams for treatment, it is necessary to monitor the copper and iron content of all streams not regulated for these parameters and the oil and grease content of rainfall runoff prior to combination to demonstrate that a particular pollutant is actually reduced rather than simply diluted. This can become a burdensome task depending upon piping logistics. In addition, it is necessary to monitor each point of discharge to the receiving body of water.

Other potential concerns of such a combined scheme are the resulting low effluent limitations for iron, copper, oil and grease which result when large quantitites of a stream not regulated for these parameters, and containing negligible concentrations of these parameters, are mixed with small quantities of wastes regulated for these parameters. It is possible that an effluent limitation could be imposed which is unattainable by conventional treatment processes.

Two processes which may have application for treatment of blowdown wastes are reverse osmosis and evaporation. Reverse osmosis has been discussed previously in this section. The evaporation can be performed in solar evaporation ponds, flash evaporators, single step distillation units or vacuum compression evaporators. In all cases, the object is the same, to concentrate the dissolved solids into a brine while returning the purified water to the cooling system.

To reduce solids buildup in the evaporation process, it is expected that the blowdown will first pass through a coagulation and sedimentation process to remove suspended solids. Sludge from the sedimentation steps, as well as the concentrated brine, may require further dewatering prior to land disposal. The devices applicable for sludge dewatering were discussed in Section 8.

The treatment of blowdown discharge requires a commitment of energy and capital investment. The solids removed during blowdown treatment will usually be disposed in the form of sludge in an approved landfill. The additional cost of blowdown treatment should, therefore, be carefully weighed against the degree of environmental impact that an untreated discharge may impart to the receiving waters.

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SECTION 11

ENVIRONMENTAL IMPACTS OF CLOSED-CYCLE COOLING SYSTEMS

11.1 BACKGROUND

11.1.1 Overview

This section provides background information on the environmental impacts resulting from the operation of closed-cycle cooling systems and indicates control measures for reducing or eliminating these impacts. Enviromental impacts of closed-cycle cooling systems can be divided into three broad categories. These are: 1) hydrological and aquatic impacts, 2) atmospheric and terrestrial impacts, and 3) land use aesthetics and noise impacts. A general description of each of these impacts follows; detailed discussions are included in subsequent subsections.

11.1.2 Hydrological and Aquatic Impacts

Hydrological and aquatic impacts are those effects caused by the make-up water intake structure itself, effects due to the water consumption, and effects created by the cooling tower blowdown. Make-up water intake structures may entrain organisms that lack sufficient mobility to withstand the pumping forces. These organisms may impinge on intake screens intended to prevent the entry of debris with the water supply. As a result, not only will these organisms be damaged or destroyed, but operating efficiencies of the closed-cycle cooling system may be reduced.

Most water consumed by a closed-cycle cooling system is lost via evaporation. Evaporative losses place a renewal burden on the water body from which the supply is drawn. This constitutes a depletion of resources, if the water body is incapable of replenishing the supply in quality and quantity.

Blowdown water has relatively high temperature and relatively high concentration of total dissolved solids. Depending on the amount and the nature of the receiving water body, cooling water blowdown can cause detrimental effects. These effects can be, for example, damage to the ecology of the receiving body of water and an overall lowering of the water quality, since excessive chemical or heat loading on the biota may alter the ecology in the area where these waters are being discharged.

11.1.3 Atmospheric and Terrestrial Impacts

Atmospheric and terrestrial impacts are those effects caused by the discharge of large quantities of warm, humid air into the atmosphere, as well as effects on biota due to the entrained impurities in the discharged vapor. Although airborne heat and water vapor emitted from closed-cycle cooling systems are not classified as pollutants, large amounts of water vapor are released to the atmosphere by these systems. Once released to the atmosphere, the excess vapor cools and may form local fog or ice conditions in the winter and may lead to increased precipitation. If the emitted water vapor mingles with a nearby industrial stack plume containing a reactive substance such as sulfur dioxide, environmental damage can occur.

Another potential atmospheric impact is that caused by drift. Drift is that fraction of the circulating cooling water exhausted to the atmosphere as water droplets. Upon leaving the cooling system, drift rises and may descend to the ground at various distances depending on the local meteorological conditions. As the water droplet evaporates, all the constituents in the water (primarily water treatment chemicals and dissolved salts) concentrate and, if deposited, can cause damage to nearby soils and vegetation, as well as materials and equipment subject to corrosion.

11.1.4 Land Use Aesthetics and Noise Impacts

Land use, aesthetics and noise impacts are those effects related to the quantity and utilization of land required by the various closed-cycle cooling systems, their visual and noise impacts to the environment as a whole. The siting of a closed-cycle cooling system on a tract of land effectively removes that land from other constructive uses. The land requirements may be relatively large as that needed for a cooling pond. Impacts to the environment, such as erosion, sedimentation, ground water contamination, defoliation, and habitat modifications, must be considered. In addition to these impacts, the noise generated by the various modes of closed-cycle cooling must be considered relative to background noise already present at the site.

Visual impacts and aesthetics are factors which must also be taken into account when the environmental impacts of closed-cycle cooling systems are reviewed. The type and elevation of the cooling system to be used, prominent viewpoints, ground cover and subjective considerations by the affected population must be taken into account.

11.2 IMPACT OF INTAKES

11.2.1 Introduction

Steam-electric power generating stations operated with closed-cycle cooling drastically reduce the requirements for cooling waters when compared to operation with a once-through cooling system. Although closed-cycle cooling requires a smaller volume of water (approximately 10,000 gpm as make-up) than that of a once-through cooling system, the volume required for a 1000-MWe power plant is comparable to the water use of a municipality of 100,000 people. Therefore, the environmental impact of intakes remains an important consideration of intake designs that have been used by other industries and which have the potential to minimize the impact of the cooling system on the environment.

A Federal Power Commission (FPC) nationwide survey(1) indicated that, out of 651 power plants surveyed, 17.2 percent used cooling towers for heat dissipation, 5.4 percent used cooling ponds, 18.9 percent used once-through cooling with saline water, 49.8 percent used once-through cooling with freshwater, and 8.7 percent used a combined system. Subsequent FPC reports based input from power plants (Form 67) show a trend of increasing use of closed-cycle cooling for dissipating heat from condensers. With the use of closed-cycle cooling, only the size of the once-through cooling intake structure is changed for closed-cycle cooling since less cooling water is required. All other engineering parameters are similar to those used in designing intake structures for once-through cooled power plants.

Except for the more recent developments in intake design, much of the present day technical information relating to evaluation and design of intakes has been presented in four major documents(2-5). These references should be consulted for additional details and results. Because less cooling water is required for closed-cycle cooling systems, there is a beneficial reduction in impact on the aquatic environment. Basically, there are three major types of biological impacts associated with present day intake structures: entrainment, entrapment or impingement, and habitat modification.

Entrainment damage occurs when plankton are drawn into the cooling system with the cooling water. Close to 100 percent of these entrained organisms can be expected to be damaged or killed by mechanical impact from the pumps, biocides, and heat. When entrained plankton includes the larval forms of fish, clams, lobster, and other aquatic organisms important to man, the result may be fewer fish and shellfish available to the public.

Organisms such as clams, crabs, and fish are too large to pass through intake screens, but are either unable to swim away from the intake or are actually attracted to it and become entraped in the intake structure where they may eventually become impinged against the screens. This impingement is caused by hydraulic forces in the intake stream at the screens. For most aquatic life, impingement will be lethal due to starvation and exhaustion when caught in the screen well, asphyxiation when forced against a screen by velocity forces which prevent proper gill movement, descaling by screen wash spray and asphyxiation by removal from water for long periods of time.

Intake structures can change the nature of habitats when the physical size and placement of these structures alter normal circulation of water or bar migration of organisms. The result is habitat modification, that is, the disruption of the normal circulation of the water body through changed flow patterns or erosion and deposition.

The most obvious methods to reduce losses caused by entrainment, entrapment, and impingement are to locate the intake in an area of low larval density, use specially developed intake screening systems which reduce attraction to fish, and regulate the mode of operation of these screens. Presently, experimental programs are being conducted at Oak Ridge National Laboratory and at various utilities to quantitatively determine the mortality associated with each component of the cooling system(6).

11.2.2 Reduction of Impact Through Location

The extent of biological damage can often be reduced drastically by identifying and avoiding important spawning areas, juvenile nursery areas, fish migration paths, and shellfishing habitats. The ability to avoid these areas will depend not only on the nature of the organisms living in the water, but also on the nature of the cooling water source. Assessing the effects of intake location on aquatic life is controversial, as attested by the numerous court litigations involving regulatory agencies, utilities, and environmental groups.

11.2.2.1 Freshwater Intakes--

River intakes have generally been placed on the shoreline upstream of the discharge. The unstratified nature of river water usually results in this being a satisfactory solution. However, when fish populations such as striped bass and salmon use the shoreline as a migratory path, the shoreline intake can act as a trap. In such cases, the intake may have to be placed offshore and built with special screens to prevent entrainment and impingement or operated in a controlled mode. An example of a controlled mode may be as simple as continuous operation of the screens or as complex as the combined operation of a once-through system with a helper tower which is periodically operated as a closed-cycle system during times when intakes can have severe adverse impacts on biota.

11.2.2.2 Small Freshwater Lakes and Reservoirs--

Small lakes are frequently stratified with a layer of warm, highly oxygenated nutrient rich water. While the use of the cooler layer for cooling purposes by power plants presents a significant engineering and economic advantage, a significant depletion of this layer can have serious repercussions. Examples include depriving lake trout of a part of their habitat and causing unwanted algae blooms when nutrient-rich water from the lower water depths is discharged at the surface. Pumping water from the surface may also be harmful because the surface is the site of primary production and the basis of the food chain. A suitable solution is to pump and discharge above the deep layer but below the primary production or photic zone(7).

11.2.2.3 Estuaries--

The design of environmentally sound intake structures for estuaries is complicated by stratification, varying salinities and tides, and the fact that estuaries are the primary production areas for aquatic organisms.

EPA stated in the guidance document for Section 316(b) (PL 92-500), that even though it is accepted that closed-cycle cooling is not necessarily the best technology available for power plant siting on estuaries despite the dramatic reduction in rates of water use, closed-cycle cooling is beginning to be employed in estuaries as the primary mode of cooling and often as a helper system(5). An example of this use is the A. M. Williams Station located in Berkely County, South Carolina, which employs mechanical draft cooling towers during the hot summer months as helpers to supplement the cooling capacity of the once-through system and to reduce the discharge temperature of the cooling water returning to the water body.

11.2.2.4 Oceans and Lakes--

In addition to the engineering problems caused by storm waves and heavy sediments in the surf area, open ocean and lake intakes must be designed to avoid major migration routes and spawning sites for fish and shellfish. Thermal stratification in large lakes is not as stable or problematical as in small lakes. In some areas, the intake should be placed offshore to avoid productive nearshore habitats formed by aquatic plants and to avoid fish spawning grounds and nearshore concentrations of warm water fish(5).

11.2.3 Reduction of Impact Through Design

11.2.3.1 Velocity Consideration--

Velocity characteristics are the most important design considerations for screening systems at intake structures. Intake velocity can be measured at three locations: 1) in the screen channel and upstream of the screen face, 2) through the screen-face or approach to the screen and 3) at entrance restrictions, such as under or over walls at the intake entrance. EPA recommends that engineering and design based on velocity considerations use the approach velocity measured through the screen face (3) since this velocity causes the highest stress to biota.

Until recently, screens at intakes were designed solely for debris removal with the major design criterion being maintenance of a low head loss across the screen. This has resulted in screen approach velocities of 0.25 to 0.65 m/s (0.8 to 2.1 ft/s or higher.

Much of the reported research on fish swimming speeds indicates that considerably lower approach velocities, on the order of 0.16 m/s (0.5 ft/s) or less are needed, if the capability of fish to swim away from an intake is required to avoid impingement (3,4). EPA recommends an approach velocity of 0.16 m/s (0.5 ft/s) or less as an intake velocity criterion to minimize entrainment and impingement.

11.2.3.2 Selection of Screen Mesh Size--

Screen efficiencies (ratio of net open area of the screen to total area) decrease rapidly as mesh size decreases. Thus, if mesh velocity is a limiting criterion (instead of or in addition to approach velocity), the total screen area must be enlarged for smaller mesh sizes. When the screen area is not enlarged after a decrease in mesh size to reduce entrainment of small fish, the resultant increase in approach velocity may increase the number of fish impinged.

The appropriate mesh size depends not only upon velocity and other engineering considerations but on the type and size of organisms needing protection. For protection of small fish larvae, special screen types which have small openings should be considered.

11.2.4 Conventional Intake System Designs

All cooling water intake systems employ a physical screening facility at some point before the condenser to remove debris that could potentially clog the condenser tubes. The most common mechanically operated screen used in closed-cycle cooling systems in U. S. power plant intakes is the vertically-rotating, single-entry, band-type screen mounted facing the waterway (Figure 11.1).

The screen system consists of the screen (usually (3/16-in) 0.474-cm mesh size), the drive mechanism, and the spray cleaning system, which washes away the debris from the screen. The screen mesh is usually arranged in individual removable panels referred to as "baskets" or "trays".

As presently used at most facilities, the conventional vertical traveling screen has several features potentially damaging to fish and other aquatic life. During normal operation and when the water is relatively free of debris, the screens are stationary. As debris collects on the screens, the increased pressure drop across the screens initiates operation to clean the screens. If the intake velocity is too high, fish can be pinned against the screen when the screens are stationary. When the screens are rotated, the fish are removed from the water and then subjected to a high pressure water spray. Any fish exposed to these hazards will be destroyed in the subsequent refuse disposal operations.

Modifications to the design and operation of conventional, vertical traveling screens can be made to minimize adverse environmental impacts. At the Surry Nuclear Station(8) (a once-through system) for example, special fish buckets (commonly referred to as Surry buckets), low pressure screen washing systems, and special fish sluice troughs to carry impinged fish away from the screens were installed (Figure 11.2). In addition, the screens are run continuously. This scheme has proven to be effective in significantly increasing the survival rate of those species which become impinged.

11.2.4.1 Intake Arrangement--

The most common intake arrangement is the combination of inlet, screen well and pump well in a single structure on the shore of a river or lake. Water usually passes first through a trash rack, then through a stop-log guide, and finally through traveling screens. Occasionally, a skimmer wall is used to insure that cooler lower strata waters will be drawn into the intake structure.

A variation of this common arrangement is to have the side walls of the intake protrude into the waterway where they create eddy currents on the downstream side of the intake. This arrangement is undesirable because fish sometimes concentrate in the eddy currents, thereby, increasing the possibility of their eventual impingement.

Another variation of the shoreline intake is the approach channel intake in which water is diverted from the main stream to flow through a canal at the end of which is the screening device. This arrangement is undesirable because the fish will tend to congregate in the approach channels and thus, increase the possibility of fish impingement.

11.2.4.2 Screen Placement--

Most conventional intakes are designed with the traveling screens set back away from the face of the intake between confining concrete walls (Figure 11.3a). This creates a zone of possible fish entrapment between the screen face and the intake entrance from which small fish may not be able to swim away. An improvement to this design would be to mount the screens flush with their supporting walls and place the trash racks out into the waterway in such a manner that fish passageways are provided in front of the screens (Figure 11.3b).

Where channel sections leading to the screens cannot be avoided due to some unusual condition, proper design of the screen supporting piers can reduce the fish entrapment potential of the area. For example, a pier which protrudes into the flow between two screens prevents fish from making the turns required to escape. Removing the protrusion of the pier (Figure 11.4) allows the fish to move to and rest in the stillwaters near the face of the pier before swimming away. In addition, screens can be oriented so that incoming water flow can guide fish to bypasses.

11.2.4.3 Velocities Across the Screens--

Uniform velocities should be maintained across the screens. When flow is not uniform across the screen, the potential for fish impingement is increased. Velocities can become non-uniform when water approaches the screen structure at an angle. Screen locations can also affect the flow distribution.

One basic consideration in the initial design of the intake is the matching of the pumping head to the pressure drop through the screens. In a two-pump system, for example, screen velocities substantially increase when only one pump is in operation. Consequently, if plans are to operate for a considerable duration with only one pump, the screens should be designed for the expected flow of one pump. Higher intake flow velocities may be permissible during periods when little fish activity is expected. During periods of high activity (spawning) or when the fish are sluggish (cold winter temperatures), low flow velocities would be maintained.

11.2.5 Alternate Intake Designs

11.2.5.1 Inclined Screens--

Inclined screens have been used in the northwestern United

States for irrigation diversions and in Canada to divert downstream migrating fish. They also have some advantages in areas of heavy debris loading. One type of inclined screen has been designed specifically with fish populations in mind (Figure 11.5). By special orientation of the screen and its cleaning mechanism, the fish can be slowly herded up the screen and kept immersed in water until they are dumped gently into the bypass trough.

The horizontal traveling screen has been designed specifically to protect fish. This screen rotates horizontally at a sharp angle to the incoming water flow. The principle is to guide fish to a point where a bypass channel can carry them to safety. It has been very effective in protecting fish but has been found to have considerable maintenance and operational problems(3).

Other types of traveling screens used in power plants in Europe, but not in the United States, include vertical axis revolving drum screens, horizontal axis revolving drum screens, and rotating disc screens. None of these were designed with fish protection in mind.

11.2.5.2 Filter Type Intake--

Many types of filter intake, e.g., leaky (porous) dams or infiltration galleries, have been developed on an experimental basis, and some have been installed in applications for power plants. The water is drawn through filter media, such as sand or stone, rather than mechanical screens. Filter intakes can be designed at low inlet velocities and thus, protect small fish and even some plankton. Several intake structures in the Great Lakes region utilize the "leaky dam" concept for mitigating environmental impact (Lakeside Power Plant, Milwaukee, Wisconsin; Bailly Generating Station, Porter County, Indiana). The "leaky dam" consists of a rubble-wall and rocks. Voids between the rocks allow sufficient passage of water through these large filters to meet plant water requirements.

Another variation of a filter type intake is the infiltration gallery. This has been used for many years for treatment of water. Infiltration galleries are cavities constructed below the water table or adjacent to a body of water which use the natural water head and permeability of the soil or bank to pass the quantity of water necessary. Soil permeability and heavy debris loads can cause clogging problems which preclude use of these designs for many waterways. However, for the relatively smaller volumes of water required to operate cooling towers, these systems show good potential applicability and use.

11.2.5.3 Fixed Screens--

Fixed screen intakes are receiving increased attention for fish protection, even though the more common type of fixed screens were not designed for fish protection. The bulk of these screens are found on small, old plants. They include those which are permanently anchored below the waterline of intakes and those which can be moved but are not capable of continuous travel. The first type of fixed screen is mounted upstream of the pumps in vertical guides to allow them to be moved to a position above the waterline. The second type involves a cylindrical screen attached to the pump suction well.

Fixed screen intakes have longer periods between cleaning cycles then do traveling screen intakes; therefore, increased impingement damage to fish is possible. The crude cleaning methods currently used on fixed screens can also be damaging to fish.

An example of fixed screens is that at Brayton Point Station, Somerset, Massachusetts. At this fossil-fueled station, fixed screens are set in place on the trash bars from May to November to prevent the impingement of horseshoe crabs(9).

11.2.5.4 Perforated Pipe, Wedge Wire Screens--

Two significantly different types of fixed screens have recently received increased attention for fish protection: the perforated pipe and the Johnson well screen. These screens are of particular interest for closed-cycle cooling systems, since they appear to provide a very small adverse environmental impact.

The original perforated pipe screen was designed for debris exclusion. It is a pipe made of perforated material which is placed in the waterway and oriented such that the passing current will sweep debris downstream. Thus, the perforated pipe is very effective in a river. The reliability of this perforated pipe system is very high(10).

Further development of the perforated pipe to prevent fish impingement and entrainment has been completed for the recirculating, close-cycle cooling systems of Washington Public Power Supply System's Nuclear Projects 1, 2, and 4(11). An intake pipe for these plants (Figure 11.6) consists of a perforated outer sleeve with 3/8-inch (.95 cm) holes over 40 percent of its area inside of which is an inner sleeve with 3/4-inch (1.9 cm) holes over 7 percent of its area. The outer sleeve prevents fish and debris from entering the system. The inner sleeve distributes the inflow evenly along the surface of the outer sleeve. The average approach velocity of the intakes was experimentally determined to be less than .12 m/s at 1.9 cm (0.4 ft/s at 3/4 in.) from the outer sleeve surface.

A promising development for minimization of both impingement and entrainment in problem environments is the application of Johnson wedge-wire well screens for power plant intakes. Johnson screens are cylinders composed of circular windings of wedged-shape wires, oriented so the wider portion of the wire faces outward (Figure 11.7). This orientation prevents clogging by providing only two-point contact for particles. The large percentage of open space, despite small aperture widths, provides uniformly low approach and screen velocities. Cylinders of wedge-wire screens can be made in a variety of sizes and mounted behind bar racks in conventional intake wells or on pipes, such as those of the perforated pipe designs(12). Fixed wedge-wire screens of conventional flat design have proven to be reliable over a number of years in the paper and pulp industry as well as the vegetable and food industry(13).

11.2.5.5 Behavioral Screening Systems--

Behavioral screening systems (behavioral barriers) employ one or more of several stimuli to cause fish to move away from an intake structure. These systems rely on the swimming ability of fish to avoid the artificial stimuli. One of the more popular innovations in intake design for power plants located on large bodies of water, such as lakes and oceans, is the velocity cap. This design is based on the observation that fish sense and, subsequently, react to vertical flow fields much more slowly than to horizontal flow fields. By inserting a cap over an open pipeline, flow can be reoriented into a horizontal flow field. Another advantage to this design is that entrance velocity can be controlled by setting the lid to the desired flow gap. This type of design is being used by the Consumers Power Company at its Palisades Nuclear Plant (closed-cycle cooling) and is proposed to be used by the Seabrook Generating Station (New Hampshire Public Service Company)(14). (See Figure 11.8)

Most behavioral systems are ineffective in the presence of stronger stimuli, such as currents, availability of food or predators and, therefore, most other systems have not demonstrated a consistent, high-level performance. Some of these systems are noted below.

Electric screens with electric fields to repel fish were tested by the National Marine Fisheries Service. They were found to be unreliable and dangerous to both fish and humans(3).

Air bubble screens, which basically consist of air pipes with equally spaced jets to provide continuous curtains of air bubbles to repel fish, have been tried in two different power plants. The system worked effectively at one plant, but not at the other(3).

Louver diverters have been used to form abrupt changes in flow velocity and direction to form barriers through which fish will not pass if an escape is provided. Individual louver panels are placed at right angles to the direction of flow and are followed by flow straighteners. The efficiency of this system increased with fish size and decreased with increased channel velocities. The louver system requires careful design and model testing with each application because of the many variables. In addition, complex and expensive fish handling systems would still be necessary to return the fish to the water source(3).

Other behavioral mechanisms, including sound and light barriers and several types of fish attraction systems, have been tried but produced only limited success. After the fish became accustomed to the barrier or attraction system, its effectiveness declined, so that the use of these systems has not gained general acceptance by utilities.

11.2.5.6 Fish Handling and Bypass Facilities--

Fish handling and bypass equipment have been used in conjunction with a conventional intake system to return impinged fish back to the waterway. Most of these systems have been developed for irrigation and hydroelectric facilities in The Western States. However, these may be applicable to utility use.

After being concentrated and removed from the screen well, the fish must be safely returned to a hospitable environment. The bypass system should be designed to minimize the time the fish are out of the water and insure their rapid return to a location far enough away from the intake to prevent re-impingement. Fish should not be returned via the discharge because the heated, chlorinated chemically-treated cooling water would be deleterious to the fish. Where conditions do not permit hydraulic conveyance, fish can be trucked back to the waterway as is routinely performed on the Snake River, Washington, to prevent fish from passing through hydroelectric dams.

Fish can be moved from one water body to another with fish pumps. The volute type of pump with screen or bladeless impellers seems to cause the least amount of damage to fish. If fish are to be moved in batches rather than continuously, special buckets or elevators can be used.

A recently proposed fish ejector system is being installed at Southern California Edison's San Onofre Nuclear Units 2 and 3(3). The system has been tested at the Redondo Generating Plant. The fish ejector system removes fish from a moving stream of water by attracting or directing fish away from the main flow into a quiet zone where the fish are trapped and, subsequently, removed to another discharge system for return downstream without injury.

11.2.6 Summary and Conclusions

Methods of reducing impact to fish populations from operation of intake structures and screens include designing and locating intake structures to help fish avoid or escape the structure itself, installing fish handling equipment to return impinged fish unharmed to the water, and using special screens whose design makes entrainment or impingement virtually impossible. The determination of which of these methods is the best available technology for a particular power plant will depend on the type of environment and the kinds of aquatic life present.

Although no strict rules can be made as to what type of intake is best for a particular plant or environment, some trends are evident. For plants on the open ocean or large lakes, submerged velocity caps offshore have reduced impingement of fish up to 95 percent in some cases. When entrainment or impingement of shoreline migratory fish in rivers is a problem, the perforated pipe offshore in the river offers a possible solution. When the entrainment of small larval fish or eggs is a potential problem, intake screens made of wedge-wire appear promising although still untested. Where no serious impingement or entrainment problems are predicted, conventional shoreline intakes and vertical traveling screens carefully designed to minimize fish entrainment will probably be sufficient.

11.3 CONSUMPTIVE WATER USE OF ALTERNATE COOLING SYSTEMS

11.3.1 General Description

In the selection of a cooling system for steam-electric power plants, three major areas require close attention: water quality, water availability, and water quantity. The parameters related to water quality and treatment are covered in Sections 7 through 10. Water availability, aside from its physical aspect, is a licensing concern involving water allocations, water rights, and permits. The consumptive water use of power plants is discussed in this section.

In once-through cooling the same amount of water taken from a water source for condenser cooling is returned to that water source, albeit at a higher temperature, usually, the amount of water taken from the water source is a small fraction of the available water; and after discharge and mixing, the net increase in water temperature will be small. This elevated temperature will cause increased evaporation (called forced evaporation) from the natural water body. Because the change in temperature relative to the natural ambient temperature will be small, the additional evaporation over the natural evaporation will also be small. In general, for once-through cooling, convective heat transfer is a significant mode of heat rejection.

For a closed-cycle cooling system using a pond, the amount of water evaporated will, in general, be greater than that for the once-through system. This is because the closed cooling pond system operates at a higher temperature than a once-through system. The net water consumption for a pond system must take into account water losses due to seepage and water gains due to precipitation, as well as water lost by evaporation. Also of importance is the natural evaporation of the pond system. If a river or stream is impounded for use as a closed-cycle cooling pond, natural evaporation from the pond must be added to the consumptive water budget. However, if the pond or reservoir serves another purpose in addition to power plant cooling, then only the enhanced or forced evaporation need be charged to the power station, while the natural evaporation could be proportionally allocated to the other users. In general, for a closed-cycle cooling system using a pond, heat transfer by evaporation ranges from 40 to 80 percent of the total heat transfer(15).

For a closed-cycle cooling system using a wet cooling tower, the amount of water evaporated is, in general, greater than the forced evaporation for the pond system(16-19). A wet tower is designed to obtain maximum direct contact of cooling water with the flowing air to insure efficient cooling of water by the evaporative process. Thus, evaporation is the primary mode of heat rejection in a wet cooling tower.

In discussing consumptive water use by cooling systems, a distinction should be made between the amount of water withdrawn from the surface water resources for cooling purposes and the amount of water "consumed" as a result of the cooling process. Water consumption is defined as that portion of water removed from and not returned to the surface water resources of a given area as a consequence of the cooling system under consideration.

The water budget of a closed-cycle cooling system for a steam-electric generating station can be expressed, in volume per unit time, by the following equation(1):

$$V = R + P + M - (G + S + B + E + I) \qquad (11.1)$$

where:

V = consumptive water use.

R = local runoff inflow.

P = precipitation impingement onto the cooling water surface.

M = make-up water.

G = net groundwater movement (negative for inflow to pond).

S = uncontrolled releases, e.g., pond seepage, overflow, etc.

B = blowdown.

E = total (natural, NE, plus forced, FE) evaporation.

I = miscellaneous inplant use.

Although several terms in Equation (11.1) are not applicable to some cooling systems, the equation is general in its application to common types of closed-cycle cooling systems.

The terms, R, P, G, S, and NE, are site dependent variables. The terms, M and B, were discussed in Section 7. The term, I, can be specifically identified for each plant. The rest of this section will be concerned with the forced evaporation component, FE, of E. Forced evaporation is that component of evaporation specifically attributable to the operation of the power plant. For cooling towers, all of the evaporation is forced; for a pond, there is a natural component, NE, which exists whether the power plant is operating or not.

11.3.2 Methods for Calculating Evaporative Losses

The water consumption for various cooling system alternatives can be predicted with models simulating the behavior of cooling towers, cooling ponds, and once-through cooling systems. The evaporative loss part of the total consumption, especially its forced evaporative component, is the term whose calculation differs greatly from system to system.

11.3.2.1 Evaporative Loss From Cooling Towers--

An evaporative or wet cooling tower is a device which cools hot water by heat exchange at the air-water interface. The process primarily involves evaporation with a small portion of sensible heat transfer. This particular type of cooling is widely used and its design is based on a well-defined technology.

Under most meteorological conditions, the exhaust air from the cooling tower is saturated. The physical processes involved in the operation of a wet cooling tower can be easily modeled to give accurate predictions of the evaporation rate. The methods of Hamilton(20) or Leung and Moore(21) can be simply represented.

For a cooling tower, the energy equation requires:

$$C_p L \Delta T = G \Delta H_a \tag{11.2}$$

where:

C_p = specific heat of water.

L = mass flow of water in the cooling system.

ΔT = water temperature range.

G = mass flow of dry air through the system.

ΔH_a = change of the air enthalpy per unit mass of dry air as the air passes through the tower.

The mass flow of water evaporated is given by:

$$E = G \Delta W_a \tag{11.3}$$

where:

ΔW_a = change in the specific humidity of the air as it passes through the tower, mass of water per unit mass of dry air.

Substituting (11.2) into (11.3) obtains:

$$E = \left(\frac{C_p L \Delta T)}{\Delta H_a}\right) \Delta W_a \tag{11.4}$$

Based on a heat and mass balance method similar to that described above, Hamilton(20) and Leung and Moore(21) have prepared graphs which provide reasonably accurate estimates of the water evaporation from wet cooling towers. The data from Reference 20 are given in Figure 11.9.

11.3.2.2 Evaporative Loss From Cooling Ponds (Forced Evaporation)--

Heat dissipation from the pond surface is accomplished through evaporation, convection, conduction, and radiation. It is highly dependent upon local meteorological conditions (solar radiation, dry bulb temperature, relative humidity or wet bulb temperature or dew point, wind speed, and cloud cover).

Determination of the forced evaporative losses for a cooling pond is a considerably more complex task than it is in the case of a wet cooling tower. This is because quantitative estimates of evaporation for cooling ponds involve many parameters which are difficult to model. There are two basic methods for estimating the forced evaporation from cooling ponds. One is called the energy budget method and is based on the First Law of Thermodynamics: it accounts for all incoming, outgoing and stored energy at the pond surface layer and enables the calculation of the energy available for evaporation. The other is called the mass transfer method and is based on the Law of Conservation of Matter. A number of empirical models have been developed based on these methods. A recent literature review(18) identified one model, Harbeck(22), based on the energy budget method and several based on the mass transfer method(23,24).

1) Energy Budget Method--Harbeck Model

As applied to a water body, this method requires that the net influx of energy be balanced by an increase of energy stored in the water. The energy budget or balance for a pond may be expressed in terms of energy rates as follows(22):

$$\Delta B + \Delta E + \Delta H + \Delta W = C \qquad (11.5)$$

where:

ΔB = increase in long wave thermal radiation emitted by the body of water.

ΔE = increase in the amount of energy used for evaporation.

ΔH = increase in the amount of energy convected from the water surface to the atmosphere as sensible heat.

ΔW = increase in the amount of sensible energy carried away by the evaporated water.

C = the amount of energy added to the cooling lake or pond by the power plant.

Equation (11.5) yields:

$$\frac{\Delta E}{C} = \frac{\Delta E}{\Delta B + \Delta E + \Delta H + \Delta W} \qquad (11.6)$$

where:

$\Delta E/C$ = percentage of heat added to the lake or pond that is used in forced evaporation.

The amount of heat added to the lake or pond, C, is known, and if the amount of energy used in forced evaporation is known, the actual volume of forced evaporation can be easily determined by dividing by the latent heat of evaporation and density of water.

The Harbeck model(22) based on this method is represented by a nomograph. The nomograph (Figure 11.10) give $\Delta E/C$ as a function of water surface temperature with wind speed at the two-meter height as a parameter. For wind speed measured at other heights, adjustments to the two-meter height can be obtained by the following formula:

$$u = u_z \ (6.56/z)^{0.3} \tag{11.7}$$

where:

u = wind speed at two meters, mph.

u_z = recorded wind speed at height z, mph.

z = height of anemometer above ground at the measuring site, feet.

Ordinarily, water surface temperature data are not readily available, and Harbeck suggested that the air temperature above the surface could be used as the water surface temperature in utilizing the nomograph. The assumption that the air temperature is approximately equal to the water surface temperature is usually acceptable according to Harbeck(22). On an annual basis in areas where ice cover does not occur, the average annual water surface temperature is usually slightly lower than the average annual air temperature because of the cooling effect of natural evaporation. The addition of heat by a power plant may cause the water surface temperature to more nearly equal the air temperature, unless the plant load is large relative to the size of the lake(22). If large air-water temperature differences exist, the procedure using Harbeck's nomograph becomes questionable because of probable errors in the surface temperature dependent energy terms of the energy budget equation.

2) Mass Transfer Method--Brady Model

This method is based on mass transfer theory (Law of Conservation of Matter). Evaporation from a water surface is treated as the turbulent transport of water in an overlying boundary layer of water vapor. All the models using this theory are quasi-empirical, and the equations take the following form:

$$E = CA \ f(u) \ (e_s - e_a) \tag{11.8}$$

where:

E = evaporation rate, million gallons per day (MGD).

C = conversion factor, 10^6 gal-ft^2/Btu-acre.

A = pond surface area, acres.

$f(u)$ = wind speed function (u is wind spped in mph), Btu/ft^2-day-mm Hg.

e_s = vapor pressure of saturated air at pond water surface temperature, mm Hg.

e_a = vapor pressure in the ambient air, mm Hg.

The wind speed function is assumed to be of the form:

$$f(u) = a + bu + cu^2, \ (\text{Btu/ft}^2\text{-day-mm Hg}) \qquad (11.9)$$

where:

a, b, and c are wind speed function coefficients and are determined experimentally for the various models used.

There are a number of empirical models available using this method. The Brady model(23) based on this method has been partially described in Section 4.2. In estimating the evaporation, the average water surface temperature, T_s, is initially unknown and is estimated, by trial and error, using Equations (4.21) to (4.25) and

$$T_s = T_e + \frac{Q_{rj}}{K} \qquad (11.10)$$

where:

T_s = water surface temperature, $^\circ$F.

T_e = equilibrium pond temperature, $^\circ$F.

Q_{rj} = rate of heat rejection per unit of lake surface area, Btu/ft^2-day.

K = surface heat exchange coefficient, Btu/ft^2-day-$^\circ$F.

11.3.3 Evaporation Rates

Evaporation rates from closed-cycle cooling systems (ponds and towers) have been estimated for all of the water resource regions in the conterminous United States(16,17,25). A summary and comparison of these results is given in Reference 18. The comparison shows that: 1) estimates of evaporation rates from cooling towers using different models are in general agreement, and 2) estimates of evaporation rates from cooling ponds prepared using the Harbeck model are about 30 percent to 50 percent of those calculated using the Brady model.

When estimating consumptive water use for cooling ponds, care should be exercised to select a model which best typifies the actual site, cooling system, and thermal load characteristics being analyzed.

11.3.4 Current and Projected Consumptive Water Use

Consumptive water use from energy related industries is increasing at an exponential rate relative to the population. The continued economic and industrial development of states having limited water availability is creating a major environmental concern in those areas of the country(18). As a result, restrictions in the allocations of water among consumptive users has or will be implemented in many states.

Current and projected consumptive water use for the steam-electric industry has been calculated and compared to that of other major consumers as shown in Table 11.1(18). The information provided in this table includes the consumptive water use of the public supply, agricultural, industrial and mining, and steam-electric components of the economy.

The consumptive water use for the steam-electric industry is projected to grow from less than two percent of the total in 1975 to greater than seven percent in the year 2000. Thus, although currently a small fraction of the total, consumptive water use from the utility industry will become an important consideration in the design and construction of power generating facilities in the future.

11.4 IMPACTS OF BLOWDOWN

11.4.1 Introduction

The blowdown impacts of closed-cycle cooling systems are primarily a problem of present day water chemistry and the treatment required to minimize fouling, corrosion, and scaling as described in Sections 7 through 10. Even though the volume of blowdown from a closed-cycle system is small when compared to the discharge volume of a once-through cooling system, the attempt to minimize blowdown by operation at high cycles of concentration (Section 7) can make the quality of the blowdown a potential environmental/toxicological hazard. Hence, it is important to insure that all the constituents of the blowdown are carefully reviewed for their short term, as well as cumulative, impacts on the environment and that the disposal of blowdown minimizes adverse environmental impacts.

11.4.2 Impacts and Biological Control Factors of Blowdown

The evaporation of large quantities of water in a closed-cycle cooling system and the cycles of concentration employed lead to the buildup of salts and other chemicals in the recirculating water system. There are three main problems associated with the chemistry of the circulating water of these systems: 1) scaling of heat transfer surfaces, 2) corrosion which results in shortened life of materials of construction, and 3) biological fouling and growth which results in reduced heat transfer, accelerated corrosion, and algal blooms. In order to minimize these problems, the degree of concentration in a cooling system is carefully controlled with various chemicals being added to control these problems (Sections 7, 8, and 9 address these problems and methods of treatment.) These chemicals affect the pH, toxicity, dissolved solids level, and general water quality of the blowdown stream.

Chemical evaluation of the blowdown waters must be routinely carried out to determine that chemical discharges do not exceed permissible standards. These standards for discharges to receiving bodies limit adverse impacts to the biota (lethal or sublethal effects).

11.4.2.1 pH and Sulfate Levels--

Generally, the conditioning of make-up water involves the adjustment of the alkalinity content of the water with sulfuric acid. This procedure attempts to achieve a certain degree of carbonate solubility in the circulating water to minimize excessive scaling. The permissible range of pH values acceptable for fish survival, however, depends upon factors, such as temperature, dissolved oxygen, and prior conditions in the receiving body of water. J. E. McKee and H. W. Wolf reported that the pH values of most inland U. S. waters containing fish ranges between 6.7 and 8.6(26). The Ohio River Valley Water Sanitation Commission concluded that direct lethal effects of pH are not produced within a range of about 6.5 and 8.2(26).

Depending upon the sulfate concentration in the make-up water, cycles of concentration, and amount of sulfuric acid required for scale control, the concentration of sulfate in the blowdown can vary over a wide range. The pH adjustment of the circulating water with sulfuric acid also increases concentration of sulfates in the blowdown stream. The maximum acceptable concentration of sulfate in raw water used for drinking water supplies is 250 mg/l except where no other drinking water supplies with a lower sulfate concentration are available.

It has been reported that waters with 500 mg/l sulfate content will not be detrimental to domestic water supplies or stock watering, and 200 mg/l will not be detrimental to irrigation. In the United States, most waters that support good fish populations contain 90 mg/l or less of sulfates(26). These factors must be considered not only in the disposal of the blowdown of cooling towers, spray ponds, and cooling lakes, but also when bodies of water are utilized for multiple purposes, one of which is power plant cooling.

11.4.2.2 Toxicity Level--

Companies which specialize in industrial water conditioning usually perform the evaluations and determine the required chemical treatment for a particular system/water condition. Many of these chemicals are proprietary compounds. Historically, toxicity data for these compounds and their constituents have been scant or not available.

Chemicals which prevent corrosion or inhibit scaling, when present in the blowdown stream, can have an adverse impact on the aquatic life of the receiving water body. Chromate salts, zinc phosphates, and organic phosphonates have been used as effective corrosion inhibitors. These chemicals have been shown to have deleterious effects to biota in the discharge area. The passage of the Toxic Substances Control Act of 1976 required detailed description of the toxic potential of the chemicals expected in the blowdown stream. Thus, it is expected that the use of chemicals for corrosion and scale inhibition in the future will most likely have less toxic effects on the biota. Concentration limitations have been placed by the Environmental Protection Agency on specific corrosion and scale inhibiting compounds in water effluents from existing and new electric power generating units (effective in 1983). The prevention of biological fouling may necessitate some degree of toxicity. Studies have shown that chlorine is an effective biocide for the control of bacterial slimes and algae at a level of 1.5 ppm free available chlorine on a once or twice-a-day injection schedule. The continuous application of chlorine is generally not necessary.

The period of treatment or use of these chemicals is defined as the time required for destruction of oxidizable biological matter within the system. This period is a variable dependent on chlorine demand of the circulating water system, seasonal variations in temperature, and environmental factors, such as spawning period for the various species of fish inhabiting the receiving water body and stages of fish development.

Effluent limitations for new electric generating units restrict the amount of chlorine which can be discharged in the blowdown, as well as the schedule of chlorine treatment (Section 9). Although the effluent limitations for steam-electric power stations were remanded to EPA for review and reissuance, much of the discussion here on effluent limitations is based on the 1974 effluent guidelines as many of these limitations are still applicable.

The maximum concentration of free available chlorine is limited to 0.5 ppm with an average value not to exceed 0.2 ppm. Also, neither free available chlorine nor total residual chlorine may be discharged for more than two hours a day per unit unless the utility can demonstrate that higher levels of chlorine or more frequent treatment is absolutely necessary for operation.

11.4.2.3 Nutrient Levels--

Since there are no limitations or restrictions on the use of corrosion inhibitors until 1983, the current discharge of these materials may have an adverse impact on the phytoplankton community of the receiving water body. Those inhibitors containing nutrients, such as phosphates or nitrates, tend to stimulate algal growth in the region of the discharge. The degree to which such a stimulus would affect the balance of the ecosystem is dependent on many interrelated parameters, including existing nutrient levels, fish population, and hydrological characteristics of the water body. The nutrient levels in the mixing zone of the blowdown stream should be estimated as the basis for assessing the potential impacts of increased algal growth.

11.4.2.4 Thermal Shock--

Thermal shock occurs when aquatic organisms are exposed to a rapid and substantial change in water temperature. Most aquatic species are unable to adjust rapidly to this temperature change and, consequently, die. The degree of thermal shock is dependent on the amount of heat added to the receiving water and the area of influence.

Thermal shock is most severe in once-through cooling systems, especially when, for example, the discharge of heated effluent is disrupted due to plant shutdown and causes sudden changes in temperature near the point of discharge. Blowdown from a closed-cycle cooling system is discharged from the cold side of the cooling system; therefore, for a cooling tower the effect of thermal shock is expected to be small. However, for a cooling pond or lake, the effect can be significant and must be determined with a biological evaluation.

11.5 ATMOSPHERIC AND TERRESTRIAL IMPACTS

11.5.1 Introduction

The atmospheric and terrestrial effects of closed-cycle cooling generally take the following forms:

1. Impact Caused by Drift: A localized deposition of water droplets which are transported out of the evaporative cooling device. These droplets may contain potentially harmful chemicals or pathogens, expecially when agricultural runoff water, municipal/industrial discharge water or saltwater cooling is employed.

2. Fogging and Icing: Ground level phenonmena caused by an elevation (above saturation level) in the water vapor content of the ambient air. During cold weather this condition can create hazardous conditions, such as icing of roads and nearby structures.

3. Climatic Modifications: Increased precipitation and cloud formation resulting from discharge to the atmosphere of large quantities of heat and water vapor from closed-cycle cooling systems. Acid rainout and sulfate and nitrate deposition are additional environmental concerns due to the possibilities of mixing of cooling tower vapor plumes with stack gas plumes.

Since drift from cooling ponds, spray ponds, and reservoirs is usually confined to the immediate vicinity of the waterbody, the discussions on drift will be limited to drift from wet cooling towers. In addition, the impact of fogging and icing from ponds, spray ponds, and reservoirs are limited to the immediate vicinity of or within a few hundred meters downwind of the water body. These effects, if they occur, are usually associated with atmospheric conditions that favor the natural formation of these effects(27,28).

11.5.2 Factors Affecting Drift Deposition and Its Impact

During normal operation of cooling towers, droplets of circulating water escape the tower and are carried upward in the rising plume. Dissolved in these droplets are naturally occuring salts, as well as chemicals added to control the growth of organisms which tend to foul heat transfer surfaces and to inhibit the corrosion of equipment. As the plume disperses, these droplets begin to evaporate to an equilibrium size. During the transformation from droplet to saturated salt particle, the fall velocity of the drop changes significantly. Eventually these particles are deposited on the ground at specific downwind distances, which are directly related to the unique trajectory of each individual particle.

In order to predict the deposition and, hence, the impact of the drift, the following parameters must be established in addition to the ambient background:

1. Water quality of the drift
2. Total drift emission rate from the cooling device
3. Particle size and mass distribution of the drift at the tower exit
4. Meteorological conditions (wind speed and direction frequency analysis)
5. Tower operating characteristics (see Section 4)

11.5.2.1 Salt Deposition Impacts--

The expected salt concentrations in the ambient air and deposition in the vicinity of the power plant as a result of cooling tower operation have been predicted analytically using various computer models(29-32). Field measurements are, at present, sparse. The presently available drift models are routinely updated, reviewed, and compared to be better able to predict and correlate plant operations with the limited field measurements available.

Studies, such as the Chalk Point experimental cooling tower project(33), critical reviews of models conducted by the American Society of Mechanical Engineers(34), and on-going evaluations by Chen and Hanna(35) and Policastro(36) have added greatly to the understanding and further refinement of these predictive models.

Because of evaporation in the tower, total dissolved solids (TDS) concentration in the circulating water can be many times that of the make-up water. Hence, the low TDS quality of the make-up water is of prime importance. For example, using ocean water for make-up, the circulating water TDS concentration could be as high as 70,000 ppm. Deposition of drift with salinity in this range would be damaging to most types of vegetation having commercial importance.

Measurements of natural (background) salt deposition has been recorded in the literature(37-39). These studies indicate that the geographic location, atmospheric conditions, and distance from the ocean are factors which affect salt deposition. Values ranging from 280 kg/km^2-mo. (2.6 lb/acre-mo.) to 3500 kg/km^2-mo. (31.0 lb/acre-mo.) have been given as reasonable deposition values(37,38).

The effect that salt deposition may have on the biota will depend on the degree of deposition, the incidence and severity of foliar damage, the species affected, and the stages of their development. The primary adverse effects cited in the literature are those of foliar necrosis and premature loss of the affected foliage(37). However, these are effects that resulted after acute levels of exposure.

The native vegetation in a coastal environment has adapted to withstand high ambient salt levels. Even though this type of vegetation is more salt tolerant, it also has its limits. It has been estimated that the minimum long-term average background airborne salt concentration needed to affect natural vegetation distribution in Eastern coastal areas is approximately 10 $\mu g/m^3$-mo. (37). Salt background levels from the shoreline have been measured from 9 $\mu g/m^3$ to 100 $\mu g/m^3$. For a tower utilizing ocean waters, it has been reported that a conservative limit for no vegetation damage could be set at 60 $\mu g/m^3$(38).

In an area where the cooling tower would utilize brackish water for make-up, such as agricultural runoff or estuary water, the growing vegetation in that area may not be as resistant to high salt deposition as seashore vegetation, and adverse effects, such as low crop yield and leaf necrosis, could occur. There are, at present, in the United States several steam-electric power plants which utilize cooling towers with brackish or salt waters. Four of these stations are: B. L. England, Atlantic City Electric Company; Jack Watson, Mississippi Power Company; P. H. Robinson, Houston Lighting and Power Company; and Chalk Point, Potomac Electric Power Company.

Damage to vegetation due to salt deposition from a natural draft cooling tower is currently being evaluated by EPRI, EPA, DOE (ERDA), and the State of Maryland at the Chalk Point Facility of the Potomac Electric Power Company. The tentative conclusions of this study indicate that the environmental effects due to cooling tower salt deposition appear to be limited to the area encompassed by the plant boundaries; hence, salt deposition from natural draft towers is minor impact to the biological community as a whole.

A recent concern, related to drift associated with the use of highly polluted waters for condenser cooling, is the potential that drift from a cooling tower using polluted waters would transfer pathogens and toxins over the area where the drift is carried and deposited. Studies supported by EPA and the Nuclear Regulatory Commission (NRC) are assessing potential effects of pathogens and toxins from drift when cooling tower make-up consists of effluents from municipal sewage treatment plants.

When using highly contaminated waters for condenser cooling, the bacteriological quality of the water must be known. If the concentrations of bacteria and/or viruses exceed that established for water intended for use by humans or animals, treatment measures for effective bacterial and viral inactivation through disinfection should be carefully considered, although there are no present standards or treatment requirements for usage of these waters for cooling purposes(40,41).

11.5.2.2 Drift Emission Rate Measurement--

Several methods are available to measure drift emission rates. When measuring ambient background rates, most of these methods rely on coated surfaces, such as liquid plastic, magnesium oxide, gelatin, petroleum jelly, and oil coatings on glass or sensitive papers, which retain the impression of the impacting water particle. When used within a cooling tower, these methods disturb the flow of air; consequently, methods have been developed which measure particle size without disturbing the air flow. In one of these methods, high intensity light is scattered while passing through the drift. A second technique uses a set of fixed components to collect a continuous isokinetic drift sample(43,44). High volume samplers and deposition pans are additional methods which collect the drift either on a filter or in pans on the ground after the drift has settled.

11.5.2.3 Particle Size and Mass Distribution--

Coated slides are an excellent device for determining particle size, whereas coated slides and sensitive papers are used in determining particle size and mass distribution. Sensitive papers are preferable for particles larger than 100 microns as reported in Central Electric Generating Board (CEGB) Technical Disclosure Bulletin No. 182(44).

Figures 11.11 and 11.12 show cumulative mass distributions of drift droplets for natural and mechanical draft cooling towers as measured at the tower outlet and as reported by various investigators(43). These figures indicate that there are significant variations in these measured values. For instance, for the standard input data used by Chen for natural-draft cooling towers, 95 percent of the total mass was made up of particles 50 microns and larger in diameter. However, the Keystone data indicate that 98 percent of the total mass consisted of particles 100 microns and larger.

Figure 11.13 shows the nominal settling rate of water droplets in air(44). The determination of deposition must account for the variations of a number of parameters: plume rise, initial salt concentration, ambient relative humidity, wind speed, and drop size, each of which has a significant effect on the trajectory of a given particle. In addition, deposition rate is directly proportional to the drift rate, which is dependent primarily on tower design.

11.5.2.4 Effects of Meteorological Conditions--

Once the drift droplets leave the tower, they are carried aloft by the rising plume. The ambient wind tends to bend the rising plume until it begins to travel horizontally. Since each drift droplet has a distinct fall velocity, the droplets begin to separate from the plume as soon as they leave the tower. The droplets are carried downwind by the wind and eventually fall to the ground. The largest droplets (diameters greater than 100 microns) have the greatest fall velocity and reach the ground after traveling 200-300 meters downwind. In contrast, the smallest droplets (diameters less than 20 microns) remain in the plume indefinitely and are carried far downwind (see Figure 11.13).

It has been reported that at high wind speeds (greater than 10 m/s), the plume will be bent over quickly and may be caught in the aerodynamic cavity region or wake downwind of the tower. If the plume is caught in the "wake" region of the tower, greatly increased ground level concentrations of the salt particles in the vicinity of the towers can occur. This condition is known as downwash. Since downwashed plumes have strong buoyant forces, these plumes will "lift off" at about 200-500 meters from the tower. Ground impact due to downwash conditions are most common for mechanical draft cooling towers due to their low heights. Hanna has estimated that at the Oak Ridge mechanical draft cooling towers this condition occurs approximately 50 percent of the time(45).

11.5.3 Control of Drift

The drift generated by a cooling tower must be controlled since its effects, as previously described, can be a nuisance, damage on-site vegetation, be a potential health hazard, and enhance the corrosion of metal structures. Methods for control of drift are primarily engineering controls, physical controls, and type of tower design. The first two methods will be discussed below, since tower design was covered in Section 4.

11.5.3.1 Engineering Controls--

The tried and proven engineering control for cooling tower drift has been the drift eliminator and is installed in most of the facilities in the United States (see Section 4). Manufacturers of cooling towers give written guarantees on the maximum percentage of the circulating water that will leave the tower as drift. (Drift eliminators are generally curved blades spaced from 1 to 2 inches apart which cause the air flow to change direction rapidly. When this occurs, water droplets in the air stream impinge upon the blades and collect to form larger droplets. These larger droplets have sufficient fall velocities to prevent re-entrainment by the rising plume.)

All manufacturers have standard guarantees for drift rate. Most cooling tower manufacturers have indicated that, in general, for both mechanical draft and natural draft towers the guaranteed drift emission rate is 0.002 percent of the circulating water volume. Measurements of actual drift from such towers have shown that the drift rate may be much less, on the order of 20 to 40 percent of the written guarantee.

11.5.3.2 Physical Controls--

Towers that use salt and brackish water should be located downwind of immediate areas of sensitive vegetation or structures. Excessive cooling tower drift may collect on switchyard insulators, and under extreme conditions (persistent high winds directed toward the switchyard) the salt buildup on the insulators could cause a flashover. Thus, if possible, this equipment should be located so that the plume passes over the switchyard a minimum amount of time. Roffman et al.(37) have found that at distances greater than 0.5 km (0.3 miles), the effects of salt deposition are insignificant.

In certain instances if efforts to limit unacceptable cooling tower drift cannot be reduced by location, the use of towers which maximize the dispersion of the drift are in order. Natural draft towers, which are generally between 300 and 500 feet in height, disperse drift more effectively than the lower profile mechanical draft towers. Round mechanical towers and fan-assisted towers have an intermediate drift dispersion capability to that of natural and mechanical draft towers.

11.5.4 Impacts of Fogging and Icing

11.5.4.1 Fogging and Icing--

The plume which exits the cooling tower, spray pond, or reservoir is warmer than the ambient air and saturated with water vapor. As it mixes with the ambient air, the plume is diluted, cooled, and a portion of the water vapor is condensed into minute droplets. These droplets scatter light, causing the plume to become visible, and give the plume the appearance of a horizontally moving cloud.

The international definition of fog and the one used by the United States National Weather Service (NWS) established fog as a condition consisting of a visible aggregate of minute water droplets or ice crystals suspended in the atmosphere near the earth's surface which reduces visibility to less than one kilometer. If the horizontal visibility is more than one kilometer, the condition is mist; if visibility is less than 0.4 km, the condition is classified as dense fog.

A main concern with visible plumes is that under certain meteorological conditions the plume can spread to ground level and cause localized fogging. If ambient temperatures are below freezing, icing conditions can occur. These concerns are more important in climates where cold, damp winters are experienced. Fogging can become a hazard, if the plume impacts visibility or enhances ice formation on roads and bridges.

11.5.4.2 Engineering Controls--

The distance from the cooling device where fogging and icing effects can occur is proportional to the above ground elevation where the plume is generated. Plumes from cooling ponds, spray ponds, and low-profile cooling towers stay close to the area of plume generation and cause fogging and icing conditions within or near the power plant property line. As in the case of drift, the natural draft cooling tower provides sufficient separation between the plume and the ground to reduce or avoid ground fogging.

G. E. MeVehil(46) compared a 76.2-m (250-ft) fan-assisted hyperbolic tower to two natural draft towers with heights of 106.7 m (350 ft) and 152.5 m (500 ft). The results show that the distance of maximum fog frequency for the fan-assisted tower is less by factors of 1.25 and 1.67 than the 106.7-m (350-ft) natural draft tower and the 152.5-m (500-ft) natural draft tower, respectively. In addition, this investigation pointed out that the fog from mechanical draft towers can be expected to occur on 100 to 150 days per year, whereas for the fan-assisted natural draft tower fog episodes can be expected to occur on 5 to 20 days per year(46). These estimates are shown in Table 11.2. Measurements made at the American Electric Power Corporation's John E. Amos Plant, Charleston, West Virginia; Muskingum River Plant, Beverly, Ohio; Big Sandy Plant, Louisa, Kentucky; and Mitchell Plant, Moundsville, West Virginia indicated that at these plants, all of which operate natural draft towers, no ground level fog was ever observed, even with winds as strong as 18 m/s (59 ft/sec)(47).

11.5.4.3 Physical Controls--

In some cases, the topography of a site can increase the potential for cooling tower fog formation. For example, in a steep river valley the tops of the ridges may be several hundred feet above the valley floor where the cooling towers are located. The plume from any cooling tower or pond cooling system might not rise above these ridges and could cause localize fogging. Hence careful siting and site-specific meteorological data are prerequisites for reducing or preventing fogging and icing conditions.

11.5.5 Effects on Weather Modification

The effects of closed-cycle cooling on modifications of weather conditions are a potential problem that is currently under study by various federal agencies. These potential modifications include increases (attributed to multi-unit installations) of precipitation and cloud cover due to the atmospheric discharge of heat and water vapor. In this regard, there have been reported instances of increased rain and snowfall related to natural draft cooling tower evaporation that have been measured at distances in excess of 40 km (25 mi)(48) from the tower. These concerns, even through long recognized, are just beginning to receive attention.

Dry cooling towers for electric power plants are now being considered for large power plants. Climatic modifications, such as cloud cover, localized wind, and local heating, have been attributed to dry cooling towers. A study performed by Boyack and Kearney(49) pointed out that a slight increase in cloud coverage is possible, a redirection and speed alteration of local wind toward a covergence zone created by the heat from the towers can be expected, and the buoyant volume will raise the local ambient air temperature. However, since at present very few power plants utilize dry cooling towers, their environmental impact is still subject to speculation.

11.5.6 Cooling Tower and Stack Plume Interaction

The interaction of a cooling tower plume with the stack gas effluents of an oil- or coal-fired steam-electric power generating facility can lead to the formation of toxic substances, such as sulfuric acid, sulfates, nitric acid, nitrates, etc. Acid drops with pH values between 2 and 3 have been reported in the visible plume (but not on the ground) from a natural draft cooling tower(50).

The composition of stack gases varies with the type of fuel used as well as the environmental/engineering measures taken to control these gaseous discharges. Hence, stack gas compositions will vary from plant to plant. The oxidation rate of SO_2, a prerequisite in acid formation, in an interactive plume has been evaluated by various investigators(51,52) and can range from 0 to 6 percent/hr. Heavy metals which are commonly found in fossil fuels, such as Pb, Mo, and Fe, can act as efficient catalysts in promoting high sulfate reaction rates. In addition, they may act synergistically to cause environmental damage. Currently, no regulatory standards for pH values have been set for atmospheric discharges.

The existing models for predicting reaction rates and acid deposition from cooling tower plumes are based on laboratory analyses. Well-designed field studies and empirical correlations are needed to properly estimate the magnitude of the problem of stack gas and cooling tower plume impact.

11.6 LAND USE, AESTHETICS, AND NOISE IMPACTS

11.6.1 Land Use - Introduction

The land requirements for the various closed-cycle cooling systems previously described in this manual have been calculated by various researchers. Table 11.3 presents estimates of land requirements on a unit power basis for these closed-cycle cooling systems(53-57).

Generally, of all presently available closed-cycle cooling systems, cooling ponds require the most land, and mechanical draft wet cooling towers require the least. However, the rationale for selection of one closed-cycle cooling system over another involves many other factors: availability of land, water availability, local climatology, socioeconomic factors, and local, state, and national laws and regulations.

The impacts that these structures may have on the land are those related to construction which disrupts, and in most cases, permanently alters the immediate habitat. Species which are rare or endangered are displaced and may be destroyed by this construction. Impacts due to operation of the various cooling systems were discussed previously in Subsections 11.2 through 11.5.

Detailed site selection programs, pre-construction surveys, and environmental control and monitoring programs during construction are methods which will provide remedial courses of action with consequent reduction of the impact caused by construction. These programs are necessarily site-specific and tailored for each locale.

The land that these cooling systems occupy is, for the immediate future, lost to the biota that occupied that portion of land, but the obvious benefits gained are related to providing electrical energy for society.

11.6.1.1 Environmental Land Impacts of Cooling Ponds--

Prior to the current environmental awareness, cooling ponds have been used for a number of years for condenser cooling by Western and Midwestern utilities. Their use was due primarily to a need to guarantee a steady supply of water in areas where the seasonal water supply fluctuated widely. Thus, cooling ponds became an attractive, cost-effective method to assure the necessary volumes of water for condenser cooling.

Presently, well over half of the cooling ponds in the United States are located in the Southwest (Texas and Oklahoma), a quarter in the Southeast, and the remainder mainly in the Midwest. The overall advantages of cooling ponds depend on the climatic conditions, topography, availability of land, and capital costs. The specific land use advantages of cooling ponds are as follows: 1) operation for extended periods of time without make-up, 2) suitability as settling basins for suspended solids, and 3) utilization for multi-purpose use, such as recreation, flood control, and an available source of water for other uses.

The primary disadvantage of cooling ponds is the amount of land required. The land used for a cooling pond is basically land that will be taken out of production. In addition, it may serve as an attraction to migratory birds. Since the waters in a cooling pond are maintained artifically warm, the migratory birds may stop in their migration either temporarily or over winter. If no food is available in the vicinity of the ponds, the birds could cause crop damage to nearby farms; hence, economic loss and liability could occur. To remedy this possible situation, adjacent land may have to be planted with grain or other feed brought in. Consequently, additional land may be required to supplement the cooling pond.

11.6.1.2 Environmental Land Impacts of Spray Ponds--

The factors involved in determining the amount of land necessary for a spray pond relate only to the desired performance of the spray pond; in other words, the heat load to be rejected by the spray pond will be the controlling factor in determining the size of the spray pond. Generally, an increase in the cooling range causes the performance of the spray pond to decrease.

The environmental impacts that spray ponds may have are intermediate between cooling ponds and towers, depending on their size and number of spray sets used. Although experience with spray ponds is limited, formation of dense fog and hard rime ice on vertical surfaces near spray ponds has been reported. Spray ponds have more serious drift problems than mechanical draft wet cooling towers because greater water deposition can occur on adjacent land and structures(58).

Berman(59) and Ryan(60) recommend that in order to minimize drift the distance between any spray nozzle and the edge of the pond be not less than 7.63 m (25 ft). In areas where strong winds are prevelent, the distance should be no less than 10.67 m (35 ft).

11.6.1.3 Environmental Land Impacts of Cooling Towers--

Investigators have quantitatively estimated the land requirements for cooling towers. Woodson(53) studied the relative land area required for both wet and dry cooling towers for an 800-MW fossil-fueled plant. The results of the study are indicated in Table 11.4.

Boyack and Kearney(61) conducted an investigation of land requirements for mechanical and natural draft dry cooling towers for 1000-MW capacity plants (nuclear- and fossil-fueled). Their estimated areas are in Table 11.5.

These tables indicate that dry cooling towers require from 2.5 to 4.2 times more land than that needed for wet cooling towers. In addition, these land requirements do not account for the additional space required for the necessary air flow around the towers and areas required for other tower-related equipment.

The land that is occupied by wet or dry cooling towers is, in most if not all cases, within the property lines of the utility. Even though the quantities of land required are sometimes impressive by themselves, they are quite insignificant compared with the total property required for operating a fossil or nuclear power plant.

11.6.2 Aesthetic Impacts

In evaluating the visual impacts of closed cooling systems, those of cooling lakes and ponds are generally the least, while those of natural draft cooling towers are the most objectionable. This is due to the fact that ponds and lakes closely resemble familiar natural bodies of water, while towers may rise to 400 or 500 feet in elevation and be the dominant feature in the immediate landscape. Various techniques have been developed in assessing visual changes due to man-made intrusions to the landscape. Some of these techniques are discussed below.

Aesthetics measurement or visual impact has often been described as an unquantifiable measure, even though it is a parameter that affects all individuals. Each individual has a very definite opinion concerning visual impact, and there are often as many opinions as there are individuals. In less subjective terms, aesthetic impact has been defined as "the change in visual quality over time resulting from the introduction of a facility into a landscape setting as viewed from the surrounding area"I62). Various methods have been used to assess aesthetic impacts of closed-cycle cooling systems. Jones et al.(63) provide a simple formula for evaluating the effect of a particular landscape measured at a specific viewpoint.

$$VQ = 1/3\ (I + V + U) \qquad (11.11)$$

where:

VQ = visual quality.

I = intactness (or wholeness of a screen).

V = vividness (or memorability of a screen).

U = unity (degree of coherence and harmany of individual elements).

Equation (11.11) is formulated so that VQ has no limiting value. Overall visual quality and its individual components are scored on a normalized scale ranging from 1 (very high quality) to 100 (very low quality). The standards to be used in scoring have been carefully defined(63). I, V, and U are scaled factors which must be carefully defined prior to assigning a numerical value. As the values of I, V, and U increase, the visual quality deteriorates.

In order to determine the change in visual impact of the landscape which results from a proposed construction modification, the following equation has been formulated(63):

$$R = \frac{VQ_a - VQ_b}{VQ_b} \qquad (11.12)$$

where:

R = ratio of change in visual quality.

VQ_a = visual quality after plant construction.

VQ_b = visual quality before plant construction.

The ratio, R, can be either positive, zero, or negative depending on whether certain attractive or unattractive features of the landscape are highlighted, unaffected, or obscured by the proposed change. If correspondingly there is no change, R will equal zero. The visual impact at a specific viewpoint may be expressed as:

$$\text{Visual Impact} = R \times P \qquad (11.13)$$

where:

P = population viewer contacts per year at a given viewpoint.

The total aesthetic impact on a landscape is, thus, the summation of the calculated composite impacts at the various viewpoints. Inputs for these composite impacts are obtained by analyzing slides which present the existing site from various views and an artist's rendition of the proposed structure superimposed on the site to give an "after" view. A panel of experts is convened to develop specific values for the formula variables presented in Equations (11.12) and (11.13).

The basic questions relating to the aesthetic impact of a closed-cycle cooling system consider site-specific factors, such as:

1. Opinions of the people living near or at the viewpoints of the cooling system who will be constantly exposed to the visual impact

2. The economic impact on real estate values in the various visually impacted neighborhoods and on future neighborhood development

Usually, those closed-cycle cooling systems that are closer to the ground, such as cooling lakes and ponds, provide the least detrimental aesthetic impact when compared to those systems that generate very large plumes and are many hundreds of feet above ground elevation (see Section 11.4). This is true even when these systems are viewed from surrounding high ground and may be due to an established familiarity with natural lakes and ponds or the fact that tall structures, such as cooling towers, require time before becoming faimilar items in the landscape. Although it may be generally said that multi-purpose use ponds cause little or no detrimental visual impact, site-specific analysis of this impact is always required.

11.6.3 Noise Impacts

The Noise Control Act of 1972 sets as its goal the attainment of an enviroment for all Americans free from noise that jeoparizes their health and welfare. In attempting to comply with this Act, the United States Department of Housing and Urban Development has established noise criteria for sound levels which occur at least 8 hr/day. These criteria define a "clearly unacceptable" area as one where the sound level exceeds 75 dBA.

A "normally unacceptable" area corresponds to sound between 45 and 65 dBA(64). These criteria, however, do not take into consideration background noise levels.

On the other hand, the Environmental Protection Agency has developed information which recommends a permissible average 24-hour outdoor noise level of 55 dBA, L_{DN} or an equivalent of 49 dBA. (L_{DN} represents the sound energy averaged over a 24-hour period with a 10 dB nighttime weighting)(65).

11.6.3.1 Noise Impact Measurement--

It is impossible to account for all factors of significance in attempting to predict the reactions and opinions of people to noise. For instance, the degree of acceptance of a power plant by its neighbors is based on their experienced unrelated to noise and can affect their reactions to noise. It is estimated that about 25 percent of the population is hardly affected by high noise levels while another 10 percent is extremely susceptible to even very small noise levels(66). Background noise and the degree to which the community has been acclimated to it are important parameters that must be considered. Background noise constitutes a measure of adaptability and serves to identify any significant deviation from the norm.

Cooling tower noise can be a major source of power plant noise. This noise is generated by a number of conditions, such as:

1. The falling water within the tower
2. The movement of air through the tower
3. The operation of the fans that mechanically create draft, bearing noises, and magnetic hum from drive motors or switchgear

Cooling tower noise levels have been measured at a number of operating facilities which use mechanical draft towers (crossflow) and natural draft towers (crossflow and counterflow)(67). Although the water flow capacity may vary by as much as a factor of four (140,000-600,000 gpm to 529,000-2,268,000 gpm), these measurements indicated that the sound level remains practically unchanged.

The average noise level at the top of a forced draft cooling tower is near 85 dBA. This noise level is not an on-site problem. However, in order to meet the EPA recommendation of 55 dBA, L_{DN} or an equivalent of 49 dBA, tower location is a critical item at some sites.

It has been estimated that at a distance of 500 feet (152.4 m) a natural draft cooling tower will generate a noise level of 61 dBA. This noise level remains approximately the same at 1000 feet (304.8 m) and does not drop to 50 dBA until a distance of 3500 feet (1066.8 m) from the tower is reached(68).

11.6.3.2 Control Measures

Measures for controlling the noise generated by falling water in cooling towers include splash decks or plates just above the water surface to create a gliding effect of the water prior to entering the basin. If the spaces between the cooling tower fill are very narrow, these create a higher noise level because of the comparatively higher air movement velocity. The reduction of this effect and that of the falling water require trade offs which need further study.

Noise generated by fans and motors and their bearings and connecting shafts can be maintained at low levels with good maintenance and lubrication. Magnetic hum generated by the motors used to drive the cooling tower fans are a very minor component of the overall cooling tower noise and can generally be ignored (69).

Various measures of noise control are used by tower manufacturers, such as two-speed motors with low speed operation at night and high speed during daytime, derating the tower with a slow speed fan, air flow silencers or attenuators, barrier walls or earthen dams(70). These measures are expensive for any type of tower, and a more suitable location, if available, would be preferable to control the noise level.

In general, forced draft cooling towers encounter greater disfavor with regard to noise than do natural draft towers. Noises from air movement over fan blades and through tower and exhaust stacks is the controlling factor for the higher noise levels. In selecting a cooling tower system, other factors, such as visible plume and aesthetics, may be more important than noise.

11.7 LICENSING AND PERMITS

11.7.1 Introduction

Power plants using closed-cycle cooling systems require a number of permits prior to start-up and operation. The process of acquiring these permits is called licensing. These cooling system related permits fall into three general categories: 1) permits required for the use and consumption of water, 2) permits required for the various discharges, and 3) permits required due to a potential impact on navigation. Federal, state, and local authorities require permits which must be acquired so as to assure compliance with the law. These required permits play an important part in the ultimate selection of the type of cooling system for a particular plant application.

11.7.2 Consumptive Water Use Permits

Paramount to the use of a closed-cycle cooling system is the acquisition of permits for the utilization and consumption of water. Federal statutes have been enacted which affect and, in a few cases, control the development of water resources in the United States. In addition, numerous interstate compacts have been enacted by the states and approved by Congress which apportion waters of interstate streams. These statutes, compacts, and treaties must be considered in successfully obtaining water for consumptive cooling purposes. However, it is important to note that there is no uniform body of laws which regulates consumptive water use in the United States.

Rules and regulations on water use vary from state to state. Customarily, water use permits are either issued by the state or are purchased or leased by the user when waters are not available for allocation.

Before withdrawing water for use by a power plant, a water usage permit must be secured. The licensing procedure requires that the applicant must indicate volume of water, time frame, and intended use of the withdrawn waters, as well as volume, rate, and quality of the water to be discharged. The pertinent river basin commission, state water engineer, state environmental quality board, Army Corps of Engineers or Bureau of Reclamation may issue this permit depending on jurisdictional authority over the water body intended for use.

In addition, the following state and local bodies or their equivalent should be consulted in the appropriate state to determine whether additional permits and licenses are required:

1. State Environmental Quality Board

2. State Air Control Commission

3. State Highway Department

4. State Board of Health

5. State Public Utilities Commission

These agencies may require that an environmental impact study be prepared stating the effects that this withdrawal may have on the specific region of the waterbody where the use takes place or on the water basin as a whole.

11.7.3 Discharge and Navigational Permits

When waste heat and certain other byproducts are discharged into the environment, they are classified as pollutants. Federal, state, and local statutes which have been legislated to protect the quality of our environment define these pollutants. The mechanisms used for implementing these statutes are regulatory licenses and/or permits.

11.7.3.1 Federal Requirements--

Various federal regulatory agencies have developed criteria that provide guidance in the preparation of the required documents and reports needed to evaluate the potential impacts of a proposed power plant and its cooling system. These guideline criteria are dynamic tools and change from time to time as more precise knowledge on the subject becomes available.

The Federal Water Pollution Control Act amendments of 1972 (the Act) established as a national goal the elimination of discharges of pollutants into navigable waters by 1985. In order to achieve this goal, the Act further requires that by 1983, all discharges will use the best available control technologies.

One pollutant, as defined by Congress in the Act, was heat. It was recognized, however, that a basic technological approach to water quality control could not be applied in the same manner to the discharge of heat as to other pollutants. Thus, Congress included within the Act in Section 316 (a) a basis for modifications of the standards as they pertain to thermal discharges from point sources. Section 316 (a) allows the discharge of heat to water bodies, if it can be demonstrated that the environmental impact of the thermal discharge will be minimal.

Pursuant to the Act, EPA, in 1974, established regulations for the discharge of heat from steam-electric generating plants. Under these regulations, subject, however, to the variance allowed under 316 (a), all existing generating plants of 500 MWe or more with once-through cooling systems which began commercial operation on or after January 1, 1970 must backfit to closed-cycle cooling systems by July 1, 1981. All generating plants that began or will begin operation on or after January 1, 1974 were likewise subject to the backfit requirements. Finally, all new plants were made subject to the thermal limitation without exception.

As of October, 1978, there are no thermal regulations written specifically for the steam-electric industry, because the regulations promulgated by EPA in 1974 were remanded to EPA in 1976. However, the federal regulations required by the National Environmental Policy Act (NEPA) do stipulate the use of best available control technology. One available control technology for the steam-electric industry is closed-cycle cooling.

Table 11.6 is a partial list of Federal Government documents to guide owners and operators of electric generating stations to prepare information needed to assess the impacts of closed-cycle cooling systems.

Federal agencies requiring permits that must be acquired as they relate to construction and operation of closed-cycle cooling systems of nuclear- or fossil-fired power plants are:

1) U. S. Army Corps of Engineers

In the construction of an intake or discharge structure, a dredging and construction permit is required for work in a navigable river and for work on (or potentially affecting) levees (Section 10 of the Rivers and Harbors Act of 1899). A permit for the discharge of dredged excavation material is also required (Public Law 92-500, Section 404). The applicant must provide information, drawings, and sketches which will indicate the manner in which these activities will be conducted, as well as the potential environmental and navigational impacts that these structures may have. Subsections 11.2, 11.3, and 11.4 of this manual provide information that can be used in reducing these impacts.

2) U. S. Coast Guard

The Coast Guard requires lighting fixtures on waterfront structures, particularly if they extend into a navigable waterway. The Coast Guard also regulates and controls all toxic and/or hazardous spills. Generally, the required information to be provided consists of drawings and descriptions that indicate that the intake and discharge structures will not interfere or create hazardous conditions in the body of water.

3) Environmental Protection Agency - NPDES Discharge Permit

The Federal Water Pollution Control Act amendments of 1972 created that National Pollutant Discharge Elimination System (NPDES) under which the regional administrator of the EPA may issue permits for the discharge of any pollutant into navigable waters. The required information must indicate quantity and type of chemical effluent to be released to the receiving body of water. The EPA effluent regulations limit the maximum concentrations of many chemicals discharged by power plants. Sections 7 through 10 of this manual review these constituents and provide information on controlling these effluents. Several of the states have been granted authority to issue NPDES permits (see Subsection 11.7.3.2).

4) U. S. Department of the Interior

When a fossil-fueled power plant is to be built on or crosses Department of the Interior land, the issuance of a permit, grant, license, contract or right-of-way is required. The Department of the Interior has guidelines for generating stations that must be followed. These guidelines require the preparation of a comprehensive environmental report in which the cooling system is one of the many systems to be reviewed. The information necessary for describing the potential impacts of the cooling system include atmospheric and aquatic thermal plume analyses, chemical constituents to be discharged into the receiving body of water, their effects on the ecosystem, population and noise impacts, etc. Section 11 of this manual addresses these concerns.

5) Federal Aviation Administration

Approval from this agency is required for construction of structures extending into the air, such as meteorological towers, stacks, or cooling towers. The required information, such as descriptions and drawings, must indicate the location and manner of lighting of these structures as well as their potential impact on air traffic and air space.

6) U. S. Nuclear Regulatory Commission

A construction permit from this agency authorizes the construction of a nuclear plant plus its cooling system in accordance with plans submitted by a utility in its application for the permit. The application includes an environmental report, a preliminary safety analysis report and necessary information for an anti-trust review.

The subsequent operating permit authorizes a utility to load fuel and begin power operations. The submittal of a final safety analysis report, an operating stage environmental report and proposed environmental technical specifications, is required as part of the application for this permit.

Both the construction and operating permit requirements must address those parameters that can cause an environmental impact due to the closed-cycle cooling system selected. Atmospheric, aquatic, terrestrial, aesthetic, and social impacts must be reviewed and their impacts assessed prior to the issuance of these permits.

Many of the permits identified in this subsection can be filed utilizing information collected for other permits. However, all permits must be obtained before operation of the plant can be initiated. Although many agencies have signed memoranda of understanding, it is incumbent upon the applicant to obtain all permits and insure that the requirements of all agencies are satisfied.

11.7.3.2 State and Local Permits--

Several states have been granted the authority to issue NPDES permits. Table 11.7 is a listing of those states that have NPDES granting authority as of the end of 1977. Others may have specific office requirements and guideline documents which must be followed. However, as a minimum the same information that would have been provided at the federal level is required by the state issuing this permit.

11.8 BENEFIT-COST ANALYSIS

11.8.1 Introduction

A benefit-cost analysis must be provided when applying for construction and operating permits for steam-electric generating stations. In performing this analysis, the economic costs and environmental impacts of closed-cycle cooling systems must be included. In general, the capital and operating costs of the cooling system are those discussed in Section 3 and provided in Subsection 4.5 of this manual. Some of the environmental factors that must be considered when comparing alternate cooling systems are also quantifiable. For example, capital and operating cost requirements of mitigative measures, such as the operation of a fish hatchery or construction of an upstream dam for flow augmentation, can be readily included in the benefit-cost analysis. On other environmental factors it is more difficult to place a monetary benefit or detriment value (e.g., number of hours of increased ground fogging). Consequently, these factors are often described on a qualitative basis. This is not to say that a cost-benefit analysis cannot be performed, but rather that this analysis will involve expert technical judgment, as well as hard data on resources affected.

Guides have been published by various regulatory governmental agencies which provide assistance in the area of environmental cost-benefit analysis(71-73). These guides should be consulted when preparing the closed-cycle cooling system sections of the benefit-cost analyses. For convenience, all of the items relating to power plant cooling systems as published in the

Nuclear Regulatory Commission Guide for preparing a benefit-cost analysis have been extracted from U. S. NRC Regulatory Guide 4.2 and assembled as Table 11.8(71). It is included here since it provides one of the most complete assessments available. It indicates those environmental parameters which can be quantified on a dollar basis and those impacts that must be assessed on some other numerical basis.

11.8.2 Benefit-Cost Analysis Methods

The classical method of benefit-cost analysis quantifies perceived costs and benefits for comparison purposes in common units of dollars(74). However, many environmental factors (e.g., noise increase and aesthetics which are not easily converted to dollar values) have, in the past, received scant consideration, while those factors which are easily converted to dollars (e.g., the capital cost of mechanical draft towers vs. natural draft towers) generally received a major consideration.

A number of models, programs, and methods which attempt to place a value, rating scale or numerical grade on the various environmental parameters have been developed and applied to the alternate cooling systems. The majority of these evaluations are based on a decision analysis concept(75). Q. B. DuBois et al. in a paper entitled "Systematic Development and Application of A Comprehensive Power Plant Site Selection Methodology" propose the use of a "figure of merit" for a site-cooling water system combination(76). This figure of merit is made up of ranking factors by "expert" groups. Others have proposed to assign a ranking scale to various environmental impacts and mathematically manipulate these values to a "best" or "least" impact. Computerized programs, such as the Department of the Interior's "Power"(77), attempt to find the least cost/impact power transmission route between two given points by making use of a similar ranking of relevant environmental site parameters and impacts.

Another technique used to arrive at a cost-benefit analysis which encompasses environmental parameters is the Delphi Decision technique(78,79). This technique is made up of two distinct phases. In phase 1, a group of "experts" (project team members, representatives from private groups, utility members, regulators) list the environmental issues of concern in a descending order of relative importance, and importance ratios or percentage values are assigned. This is done independently by each member of the group of experts. In phase 2, the individual results are analyzed by a non-participating moderator, normalized to a percentage scale, and returned to the group for review. This process is repeated until a consensus is reached.

H. T. Odum et al. (80) have attempted to convert environmental field data into energy flow equivalent values or energy units by using the "Lotka Maximum Power Principle" (81), which deals with the useful work accomplished from energy flowing in a system and not just the heat equivalent value of that energy.

However, these elegant but complex calculations have not received a great deal of acceptance by the engineering/biological community dealing with environmental cost-benefit analysis of cooling systems.

Others (82) have attempted to utilize dollar values for impacts on fish by employing the "values per reported catch" for commercial fishermen and other factors, such as time spent fishing, stock of fish per acre and distance traveled to fishing area, to reflect a dollar value for impact on recreational fisherman. These factors, although valid per se, are strictly short-term impact values and fail to consider the potential long-term impact on the overall environment.

The majority of the methodologies presently employed for the evaluation of environmental cost-benefit analysis considers objective, as well as subjective utilization concurrence by a group. These methods have proven to be of value. For these environmental cost-benefit methodologies to represent the actual facts, a broad data base, efficient information processes, a multi-disciplinary approach, and public opinion poll and survey information must be considered.

TABLE 11.1. PROJECTED CONSUMPTIVE WATER USE, MGD(22)

		Year	
Category	1975	1985	2000
Public Supply	8,485	9,594	10,978
Agriculture	99,149	107,281	107,467
Industry & Mining	8,130	11,395	17,760
Steam-Electric	1,440	4,110	10,598
Total Consumption	117,204	132,380	146,803

TABLE 11.2. ESTIMATED FOG FREQUENCIES FOR NATURAL DRAFT AND HYBRID COOLING TOWERS(47)

Type of Tower	Size		Fog Frequency (Hours/Year)	Distance of Max. Freq. (km)
	Height	Diameter		
Hybrid (Powered Hyperbolic)	76.2m (250 ft)	54.8m (180 ft)	25 - 100	12
Natural Draft	106.7m (350 ft)	54.8m (180 ft)	15 - 75	15
Natural Draft	152.5m (500 ft)	67.1m (220 ft)	5 - 40	20

TABLE 11.3. APPROXIMATE LAND REQUIRED BY VARIOUS COOLING SYSTEMS

Cooling Method	Acre/MWe	m^2/MWe
Cooling Pond(55)	1.00 - 3.00	$(4.05 - 12.15) \times 10^3$
Jet Spray Pond(54,57)	0.05 - 0.30	$(0.202 - 1.215) \times 10^3$
Natural Draft, Wet Tower(53,56)	$(4.58 - 5.06) \times 10^{-3}$	18.55 - 20.50
Mechanical Draft, Wet Tower(53)	2.86×10^{-3}	11.58
Natural Draft, Dry Tower(53)	21.20×10^{-3}	85.80
Mechanical Draft, Dry Tower(53)	6.98×10^{-3}	28.30

TABLE 11.4. RELATIVE AREA REQUIREMENTS FOR ALTERNATE COOLING TOWER SYSTEMS (800-MWe FOSSIL POWER PLANT(53)

	Cooling Tower System	
	Wet Tower	Dry Tower
Natural Draft	1.64 hectare (4.05 acre)	6.87 hectare (16.9 acre)
Mechanical Draft	0.90 hectare (2.22 acre)	2.26 hectare (5.58 acre)

TABLE 11.5. LAND REQUIREMENTS FOR DRY COOLING TOWERS FOR REPRESENTATIVE 1000-MWe POWER PLANTS(61)

	Fossil	Nuclear	
Cooling Tower		LWR+	HTGR*
Natural Draft	1.90 hectare (4.7 acres)	4.50 hectare (11.1 acres)	2.51 hectare (6.2 acres)
Mechanical Draft	2.75 hectare (6.8 acres)	4.13 hectare (10.2 acres)	3.08 hectare (7.6 acres)

+LWR - Light water reactor

*HTGR - High temperature gas-cooled reactor

TABLE 11.6. GUIDANCE LIST OF DOCUMENTS AVAILABLE FROM THE FEDERAL GOVERNMENT FOR FILING PERMITS RELATED TO CLOSED-CYCLE COOLING SYSTEMS

Name of Laws, Statutes, Guidance Documents, etc.	Brief Description
U.S. laws, statutes, etc., 1972. Federal Water Pollution Control Act Amendments of 1972.	The objective of this law (P.L. 92-500) is to restore and maintain the chemical, physical, and biological integrity of the Nation's waters.
U.S. Environmental Protection Agency. 1974. Thermal discharges: 316(a) regulations. Federal Register 39(196):36176-36184.	Section 316(a) regulations require that the thermal effluent "assure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in and on that body of water into which the discharge is to be made."
U.S. Environmental Protection Agency. 1975. EPA/NRC 316(a) technical guidance manual and guide for thermal effects sections of nuclear power plant environmental impact statements: a first step towards standardizing biological data requirements for the EPA/NRC memorandum of understanding.	This manual describes the information which should be developed in connection with making technical determinations under Section 316(a) of the Federal Water Pollution Control Act Amendments of 1972.
U.S. Environmental Protection Agency. 1976. Best technology available for the location, de-	Section 316(b) final regulations which require location, design, construction, and capacity of

(continued)

TABLE 11.6 (continued)

Name of Laws, Statutes, Guidance Documents, etc.	Brief Description
sign, construction, and capacity of cooling water intake structures for minimizing adverse environmental impact. Federal Register 41(31):17387-17390.	cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts.
U.S. Environmental Protection Agency. 1976. Guidance for determining best technology available for the location, design, construction, and capacity of cooling water intake structures for minimizing environmental impact, Section 316(b), P.L. 92-500	This guidance manual describes the information and techniques needed to evaluate cooling water intake structures and allow for determination of the best technology available for minimizing adverse environmental impact.
U.S. Environmental Protection Agency. 1974. Steam electric power generating point source category: effluent guidelines and standards. Federal Register 39(196):36186-36207.	Regulations establish final effluent limitations and guidelines for existing sources and standards of performance and pretreatment standards for new sources in the steam electric power generating category.
U.S. Environmental Protection Agency. 1976. Steam electric power generation point source category: effluent guidelines and standards (Cooling lakes amendment). Federal Register 41(60):12694-12696.	Proposed regulations would permit the use of a "recirculating cooling water body" (cooling lake or pond) for certain specified sources.
U.S. Environmental Protection	This document presents the find-

(continued)

TABLE 11.6 (continued)

Name of Laws, Statutes, Guidance Documents, etc.	Brief Description
Agency. 1974. Development document for effluent limitations guidelines and new source performance standards for the steam electric power generating point source category. (EPA 440/1-74/029-a)	ings of an extensive study of the steam electric power generating point source category for the purpose of developing effluent limitations, guidelines, and standards for the industry in compliance with and to implement Sections 304, 306, and 307 of the Federal Water Pollution Control Act Amendments of 1972.
U.S. Environmental Protection Agency. 1976. Development document for best technology available for the location, design, construction, and capacity of cooling water intake structures for minimizing adverse environmental impact. (EPA 440/1-76/015-a)	This document presents the findings of an extensive study of the available technology for the location, design, construction, and capacity of cooling water intake structures for minimizing adverse environmental impact in compliance with and to implement Section 316(b) of the Federal Water Pollution Control Act Amendments of 1972.
U.S. Nuclear Regulatory Commission. 1976. Regulatory Guide 4.2: Preparation of environmental reports for nuclear power stations.	This document identifies the information needed by the Nuclear Regulatory Commission in its assessment of the potential environmental effects of the proposed nuclear facility and establishes a format acceptable to the NRC for its presentation.
U.S. Atomic Energy Commission.	This guide discusses the major

(continued)

TABLE 11.6 (continued)

Name of Laws, Statutes, Guidance Documents, etc.	Brief Description
1975. Regulatory Guide 4.7: General site suitability criteria for nuclear power stations.	site characteristics related to public health and safety and environmental issues which the NRC staff considers in determining the suitability of sites for light-water-colled (LWR) and high temperature gas-cooled (HTGR) nuclear power stations
U.S. Nuclear Regulatory Commission. 1975. Regulatory Guide 4.8: Environmental technical specifications for nuclear power plants.	This regulatory guide provides guidance to applicants on the preparation of proposed environmental technical specifications and includes an identification of their principal content and a standard format.
U.S. Department of the Interior. Guidelines for the Preparation of Environmental Reports for Fossil-Fueled Steam Electric Generating Stations, November 1976.	This document identifies the information required by the Department of Interior in its assessment of the potential environmental effects of a proposed fossil-fueled facity when the Department of Interior is designated as the lead Federal Agency.
U.S. Department of the Army. Regulation No. 1105-2-507, "Planning, Preparation and Coordination of Environmental Statements", February 1973.	This document identifies information needed by the U.S. Army Corps of Engineers when a portion of a steam-electric power generating facility infringes on a navigable waterway so that environmental/safety impacts can be assessed and permits issued

(continued)

TABLE 11.6 (continued)

Name of Laws, Statutes, Guidance Document, etc.	Brief Description
	or denied.
U.S. Coast Guard, "Procedures for Considering Environmental Impacts." Commandant Instruction 5922.10B, 1975.	This document identifies those parameters that may create an environmental/safety impact when a portion of a steam-electric power generating facility infringes on a navigable waterway.
U.S. Department of Transportation, Federal Aviation Administration, AC 70-7460-LA, "Obstruction Marking and Lighting", January 1972.	This document identifies those parameters that may create an environmental/safety impact when a portion of a steam-electric power generating facility infringes on airspace.
U.S. Fish and Wildlife Service. 1975. Review of fish and wildlife aspects of proposals in or affecting navigable waters: Adoption of guidelines. Federal Register 49(231):55810-55824.	The final guidelines describe the objectives, policies and procedures to be followed in the review of proposals for works and activities in or affecting navigable waters that are sanctioned, permitted, assisted or conducted by the Federal government.
U.S. Nuclear Regulatory Commission. 1976. Regulatory Guide 4.11: Terrestrial environmental studies for nuclear power stations.	This regulatory guide provides technical information for the design and execution of terrestrial environmental studies for nuclear power stations.

TABLE 11.7. STATES THAT HAVE NPDES GRANTING AUTHORITY (AS OF 31 DECEMBER 1977)

State	Administrative Agency
California	California Water Resources Control Broad 1416 North Street Sacramento, CA 95814
Colorado	Department of Health 4210 East 11th Avenue Denver, CO 80220
Connecticut	Dept. of Environmental Protection State Office Building Harford, CT 06115
Delaware	Dept. of Natural Resources and Environmental Control Tatnall Building Dover, DE 19901
Georgia	Georgia Dept. of Natural Resources Environmental Protection Division 47 Trinity Avenue SW Atlanta, GA 30334
Hawaii	Department of Health Environmental Health Division P. O. Box 3378 Honolulu, HI 96801
Indiana	Stream Pollution Control Board 1330 West Michigan Street Indianapolis, IN 46206
Kansas	Kansas State Dept. of Health Division of Environmental Health 535 Kansas Avenue Topeka, KS 66603

(continued)

TABLE 11.7 (continued)

State	Administrative Agency
Maryland	Maryland Dept. of Natural Resources Water Resources Administration State Office Building Annapolis, MD 21401
Michigan	Dept. of Natural Resources Water Resources Commission Stevens T. Mason Building Lansing, MI 48926
Minnesota	Minnesota Pollution Control Agency 1935 W. County Road B2 Roseville, MN 55113
Mississippi	Mississippi Air and Water Pollution Control Commission 416 North State Street Jackson, MS 39205
Missouri	Clean Water Commission 1014 Madison Street P. O. Box 154 Jefferson City, MO 65101
Montana	Dept. of Health and Environmental Sciences Cogswell Building Helena, MT 59601
Nebraska	Nebraska Dept. of Environmental Control P. O. Box 94653 State House Station Lincoln, NE 68509
Nevada	Dept. of Human Resources Bureau of Environmental Health Capital Complex 1209 Johnson Street Carson City, NV 89701

(continued)

TABLE 11.7 (continued)

State	Administrative Agency
New York	Dept. of Environmental Conservation 50 Wolf Road Albany, NY 12233
North Carolina	Department of Natural and Ecologic Resources P. O. Box 27687 Raleigh, NC 27611
North Dakota	Dept. of Health State Capital Bismark, ND 58501
Ohio	Ohio Environmental Protection Agency 450 E. Town Street Columbus, OH 43216
Oregon	Dept. of Environmental Quality Water Quality Control Division 1400 SW Fifth Avenue Portland, OR 97201
South Carolina	Dept. of Health and Environmental Control 2600 Bull Street Columbia, SC 29201
Vermont	Environmental Conservation Agency Montpelier, VT 05602
Virginia	State Water Control Board P. O. Box 11143 Richmond, VA 23230
Virgin Islands	Dept. of Conservation and Cultural Affairs P. O. Box 278 Charlotte Amalie St. Thomas, VI 00801

(continued)

TABLE 11.7 (continued)

State	Administrative Agency
Washington	Dept. of Ecology Olympia, WA 98501
Wisconsin	Environmental Protection Division Dept. of Natural Resources Madison, WI 53701
Wyoming	Dept. of Environmental Quality State Office Building Cheyenne, WY 82001

TABLE 11.8*. ENVIRONMENTAL FACTORS TO BE USED IN COMPARING ALTERNATIVE PLANT SYSTEMS (71).

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
1. Natural surface water body	(Specify natural water body affected)			
1.1 Impingement or entrapment by cooling water intake structure	1.1.1 Fish[b]	Juveniles and adults are subject to attrition.	Percent of harvestable or adult population destroyed per year for each important species.	Identify all important species as defined in Section 2 2. Estimate the annual weight and number of each species that will be destroyed. (For juveniles destroyed, only the expected population that would have survived naturally need be considered.) Compare with the estimated weight and number of the species population in the water body.
1.2 Passage through or retention in cooling systems	1.2.1 Phytoplankton and zooplankton	Plankton population (excluding fish) may be changed due to mechanical, thermal, and chemical effects.	Percent changes in production rates and species diversity.	Field studies are required to estimate (1) the diversity and production rates of readily recognizable groups (e.g., diatoms, green algae, zooplankton) and (2) the mortality of organisms passing through the condenser and pumps. Include indirect effects[c] which affect mortality.

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[a] Applicant may substitute an alternative unit of measure where convenient. Such a measure should be related quantitatively to the unit of measure shown in this table.

[b] "Fish" as used in this table includes shellfish and other aquatic invertebrates harvested by man.

[c] Indirect effects could include increased disease incidence, increased predation, interference with spawning, changed metabolic rates, hatching of fish out of phase with food organisms.

*From U.S. NRC Regulatory Guide 4.2, Revision 2 "Preparation of Environmental Reports for Nuclear Power Stations", July 1976 (Table 4). Where references to sections appear, these refer to sections in the Guide.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	1.2.2 Fish	All life stages (eggs, larvae, etc.) that reach the condenser are subject to attrition.	Percent of harvestable or adult population destroyed per year for each important species.	Identify all important species as defined in Section 2.2. Estimate the annual weight and number of each species that will be destroyed. (For larvae, eggs, and juveniles destroyed, only the expected population that would have survived naturally need be considered.) Compare with the estimated weight and number of the species population in the water body.
1.3 Discharge area and thermal plume	1.3.1 Water quality, excess heat	The rate of dissipation of the excess heat, primarily to the atmosphere, will depend on both the method of discharge and the state of the receiving water (i.e., ambient temperature and water currents).	Acres and acre-feet	Estimate the average heat in Btu's per hour dissipated to the receiving water at full power. Estimate the water volume and surface areas within differential temperature isotherms of 2, 3, and 5°F under conditions that would tend, with respect to annual variations, to maximize the extent of the areas and volumes.
	1.3.2 Water quality, oxygen availability	Dissolved oxygen concentration of receiving waters may be modified as a consequence of changes in the water temperature, the translocation of water of different quality, and aeration.	Acre-feet.	Estimate volumes of affected waters with concentrations below 5, 3, and 1 ppm under conditions that would tend to maximize the impact.
	1.3.3 Fish (nonmigratory)	Fish[b] may be affected directly or indirectly because of adverse conditions in the plume.	Net effect in pounds per year (as harvestable or adult fish by species of interest).	Field measurements are required to establish the average number and weight (as harvestable or adults) of important species (as defined in Section 2.2). Estimate their mortality in the receiving water from direct and indirect effects.[c]

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	1.3.4 Fish (migratory)	Suitable habitats (wetland or water surface) may be affected.	Acres of defined habitat or nesting area.	Determine the areas impaired as habitats because of thermal discharges, including effects on food resources. Document estimates of affected population by species.
	1.3.5 Wildlife (including birds and aquatic and amphibious mammals and reptiles).	A thermal barrier may inhibit migration, both hampering spawning and diminishing the survival of returning fish.	Pounds per year (as adult or harvestable fish by species of interest).	Estimate the fraction of the stock that is prevented from reaching spawning grounds because of plant operation. Prorate this directly to a reduction in current and long-term fishing effort supported by that stock. Justify estimate on basis of local migration patterns, experience at other sites, and applicable State standards.
1.4 Chemical effluents	1.4.1 Water quality, chemical	Water quality may be impaired.	Acre-feet, %.	The volume of water required to dilute the average daily discharge of each chemical to meet applicable water quality standards should be calculated. Where suitable standards do not exist, use the volume required to dilute each chemical to a concentration equivalent to a selected lethal concentration for the most important species (as defined in Section 2.2) in the receiving waters. The ratio of this volume to the annual minimum value of the daily net flow, where applicable, of the receiving waters should be expressed as a percentage, and the largest such percentage reported. Include the total solids if this is a limiting factor. Include in this calculation the blowdown from cooling towers.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	1.4.2 Fish	Aquatic populations may be affected by toxic levels of discharged chemicals or by reduced dissolved oxygen concentrations.	Pounds per year (by species of fish).	Total chemical effect on important species of aquatic biota should be estimated. Biota exposed within the facility, as well as biota in receiving waters, should be considered. Supporting documentation should include reference to applicable standards, chemicals discharged, and their toxicity to the aquatic populations affected.
	1.4.3 Wildlife (including birds and aquatic and amphibious mammals and reptiles).	Suitable habitats for wildlife may be affected.	Acres.	Estimate the area of wetland or water surface impaired as a wildlife habitat because of chemical contamination, including effects on food resources. Document the estimates of affected population by species.
	1.4.4 People	Recreational water uses (boating, fishing, swimming) may be inhibited.	Lost annual user days and area (acres) or shoreline miles for dilution.	The volume of the net flow to the receiving waters required for dilution to reach accepted water quality standards must be determined on the basis of daily discharge and converted to either surface area or miles of shore. Cross-sectional and annual minimum flow characteristics should be incorporated where applicable. Annual number of visitors to the affected area or shoreline must be obtained. This permits estimation of lost user-days on an annual basis. Any possible eutrophication effects should be estimated and included as a degradation of quality.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
1.5 Radionuclides discharged to water body	1.5.1 Aquatic organisms	Radionuclide discharge may introduce a radiation level which adds to natural background radiation.	Rad per year.	Sum dose contributions from radionuclides expected to be released.
	1.5.2 People, external	Radionuclide discharge may introduce a radiation level which adds to natural background radiation for water users.	Rem per year for individual; man-rem per year for estimated population as of the first scheduled year of plant operation.	Sum annual dose contributions from nuclides expected to be released. Calculate for above-water activities (skiing, fishing, boating), in-water activities (swimming), and shoreline activities.
	1.5.3 People, ingestion	Radionuclide discharge may introduce a radiation level which adds to natural background radiation for ingested food and water.	Rem per year for individuals (whole body and organ); man-rem per year for population as of first scheduled year of plant operation.	Estimate biological accumulation in foods, and intake by individuals and population. Calculate doses by summing results for expected radionuclides.
1.6 Consumptive use	1.6.1 People	Drinking water supplies drawn from the water body may be diminished.	Gallons per year.	Where users withdraw drinking water supplies from the affected water body, lost water to users should be estimated. Relevant delivered costs of replacement drinking water should be included.
	1.6.2 Agriculture	Water may be withdrawn from agricultural usage and use of remaining water may be degraded.	Acre-feet per year.	Where users withdrawing irrigation water are affected, the loss should be evaluated as the sum of two volumes; the volume of the water lost to agricultural users and the volume of dilution water required to reduce concentrations of dissolved solids in remaining water to an agriculturally acceptable level.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	1.6.3 Industry	Water may be withdrawn for industrial use.	Gallons per year.	
1.7 Plant construction (including site preparation)	1.7.1 Water quality, physical	Turbidity, color or temperature of natural water body may be altered.	Acre-feet and acres.	The volume of dilution water required to meet applicable water quality standards should be calculated. The areal extent of the effect should be estimated.
	1.7.2 Water quality, chemical	Water quality may be impaired.	Acre-feet, %.	To the extent possible, the applicant should treat problems of spills and drainage during construction in the same manner as in 1.4.1.
1.8 Other impacts				The applicant should describe and quantify any other environmental effects of the proposed plant that are significant.
1.9 Combined or interactive effects				Where evidence indicates that the combined effect of a number of impacts on a particular population or resource is not adequately indicated by measures of the separate impacts, the total combined effect should be described.
1.10 Net effects				See discussion in Section 5.7.
2. Ground Water				
2.1 Raising/lowering of ground water levels	2.1.1 People	Availability or quality of drinking water may be decreased and the functioning of existing wells may be impaired.	Gallons per year.	Volume of replacement water for local wells actually affected must be estimated.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	2.1.2 Plants	Trees and other deep-rooted vegetation may be affected.	Acres.	Estimate the area in which ground water level change may have an adverse effect on local vegetation. Report this acreage on a separate schedule by land use. Specify such uses as recreational, agricultural and residential.
2.2 Chemical contamination of ground water (excluding salt).	2.2.1 People	Drinking water of nearby communities may be affected.	Gallons per year.	Compute annual loss of potable water.
	2.2.2 Plants	Trees and other deep-rooted vegetation may experience toxic effects.	Acres.	Estimate area affected and report separately by land use. Specify such uses as recreational, agricultural and residential.
2.3 Radionuclide contamination of ground water	2.3.1 People	Radionuclides that enter ground water may add to natural background radiation level for water and food supplies.	Rem per year for individuals (whole body and organ); man-rem per year for population as of year of first scheduled year of plant operation.	Estimate intakes by individuals and populations. Sum dose contributions for nuclides expected to be released.
	2.3.2 Plants and animals	Radionuclides which enter ground water may add to natural background radiation level for local plant forms and animal population.	Rad per year.	Estimate uptake in plants and transfer to animals. Sum dose contributions for nuclides expected to be released.
2.4 Other impacts on ground water				The applicant should describe and quantify any other environmental effects of the proposed plant which are significant.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
3. Air				
3.1 Fogging and icing (caused by evaporation and drift)	3.1.1 Ground transportation	Safety hazards may be created in the nearby regions in all seasons.	Vehicle-hours per year	Compute the number of hours per year that driving hazards will be increased on paved highways by fog and ice from cooling towers and ponds. Documentation should include the visibility criteria used for defining hazardous conditions on the highways actually affected.
	3.1.2 Air transportation	Safety hazards may be created in the nearby regions in all seasons.	Hours per year, flights delayed per year.	Compute the number of hours per year that commercial airports will be closed to visual (VFR) and instrumental (IFR) air traffic because of fog and ice from cooling towers. Estimate number of flights delayed per year.
	3.1.3 Water transportation	Safety hazards may be created in the nearby regions in all seasons.	Hours per year, number of ships affected per year.	Compute the number of hours per year ships will need to reduce speed because of fog from cooling towers or ponds or warm water added to the surface of the river, lake or sea.
	3.1.4 Plants	Damage to timber and crops may occur through introduction of adverse conditions.	Acres by crop.	Estimate the acreage of potential plant damage by crop.
3.2 Chemical discharge to ambient air	3.2.1 Air quality, chemical	Pollutant emissions may diminish the quality of the local ambient air.	% and pounds or tons.	The actual concentration of each pollutant in ppm for maximum daily emission rate should be expressed as a percentage of the applicable emission standard. Report weight for expected annual emissions.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	3.2.2 Air quality, odor	Odor in gaseous discharge or from effects on water body may be objectionable.	Statement.	A statement must be made as to whether odor originating in plant is perceptible at any point offsite
3.3 Radionuclides discharged to ambient air and direct radiation from radioactive materials (in-plant or being transported).	3.3.1 People, external	Radionuclide discharge or direct radiation may add to natural background radiation level.	Rem per year for individuals (whole body and organ); man-rem per year for population as of year of first scheduled operation.	Sum dose contributions from nuclides expected to be released.
	3.3.2 People, ingestion	Radionuclide discharge may add to the natural radioactivity in vegetation and in soil.	Rem per year for individuals (whole body and organ); man-rem per year for population as of year of first scheduled operation.	For radionuclides expected to be released estimate deposit and accumulation in foods. Estimate intakes by individuals and populations and sum results for all expected radionuclides.
	3.3.3 Plants and animals	Radionuclide discharge may add to natural background radioactivity of local plant and animal life.	Rad per year.	Estimate deposit of radionuclides on, and uptake in plants and animals. Sum dose contributions for radionuclides expected to be released.
3.4 Other impacts on air.				The applicant should describe and quantify any other environmental effects of the proposed plant that are significant.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
4. Land				
4.1 Site selection	4.1.1 Land, amount	Land will be preempted for construction of nuclear power plant, plant facilities, and exclusion zone.	Acres.	State the number of acres preempted for plant, exclusion zone, and accessory facilities such as cooling towers and ponds. By separate schedule, state the type and class of land preempted (e.g., scenic shoreline, wet land, forest land, etc.).
4.2 Construction activities (including site preparation)	4.2.1 People (amenities)	There will be a loss of desirable qualities in the environment due to the noise and movement of men, material and machines.	Total population affected, years.	The disruption of community life (or alternatively the degree of community isolation from such irritations) should be estimated. Estimate the number of residences, schools, hospitals, etc., within area of visual and audio impacts. Estimate the duration of impacts and total population affected.
	4.2.2 People (accessibility of historical sites)	Historical sites may be affected by construction.	Visitors per year.	Determine historical sites that might be displaced by generation facilities. Estimate effect on any other sites in plant environs. Express net impact, in terms of annual number of visitors.
	4.2.3 People (accessibility of archeological sites)	Construction activity may impinge upon sites of archeological value.	Qualified opinion.	Summarize evaluation of impact on archeological resources in terms of remaining potential value of the site. Referenced documentation should include statements from responsible county, State or Federal agencies, if available.

(continued)

TABLE 11.8* (continued)

Primary Impact		Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	4.2.4	Wildlife	Wildlife may be affected.	Qualified opinion.	Summarize qualified opinion including views of cognizant local and State wildlife agencies when available, taking into account both beneficial and adverse affects.
	4.2.5	Land (erosion)	Site preparation and plant construction will involve cut and fill operations with accompanying erosion potential.	Cubic yards and acres.	Estimate soil displaced by construction activity and erosion. Beneficial and detrimental effects should be reported separately.
4.3 Plant operation	4.3.1	People (amenities)	Noise may induce stress.	Number of residents, school populations, hospital beds.	Use applicable state and local codes for offsite noise levels for assessing impact. If there is no code, consider nearby land use, current zoning, and ambient sound levels in assessing impact. The predicted sound level may be compared with the published guidelines of the EPA, American Industrial Hygiene Association, and HUD.
	4.3.2	People (aesthetics)	The local landscape as viewed from adjacent residential areas and neighboring historical, scenic, and recreational sites may be rendered aesthetically objectionable by the plant facility.	Qualified opinion.	Summarize qualified opinion including views of cognizant local and regional authorities when available.
	4.3.3	Wildlife	Wildlife may be affected.	Qualified opinion.	Summarize qualified opinion including views of cognizant local and State wildlife agencies when available, taking into account both beneficial and adverse effects.

(continued)

TABLE 11.8* (continued)

Primary Impact	Population or Resources Affected	Description	Unit of Measure[a]	Method of Computation
	4.3.4 Land, flood control	Health and safety near the water body may be affected by flood control.	Reference to Flood Control District approval	Reference must be made to regulations of cognizant Flood Control Agency by use of one of the following terms: Has NO IMPLICATIONS for flood control, COMPLIES with flood control regulation.
4.4 Salts discharged from cooling towers	4.4.1 People	Intrusion of salts into ground water may affect water supply.	Pounds per square foot per year.	Estimate the amount of salts discharged as drift and particulates. Report maximum deposition. Supporting documentation should include patterns of deposition and projection of possible effect on water supplies.
	4.4.2 Plants and animals	Deposition of entrained salts may be detrimental in some nearby regions.	Acres.	Salt tolerance of vegetation in affected area must be determined. That area, if any, receiving salt deposition in excess of tolerance (after allowance for dilution) must be estimated. Report separately an appropriate tabulation of acreage by land use. Specify such uses as recreational, agricultural, and residential. Where wildlife habitat is affected, identify populations.
	4.4.3 Property resources	Structures and movable property may suffer degradation from corrosive effects.	Dollars per year.	If salt spray impinges upon a local community, property damage may be estimated by applying to the local value of buildings, machinery, and vehicles a differential in average depreciation rates between this and a comparable seacoast community.

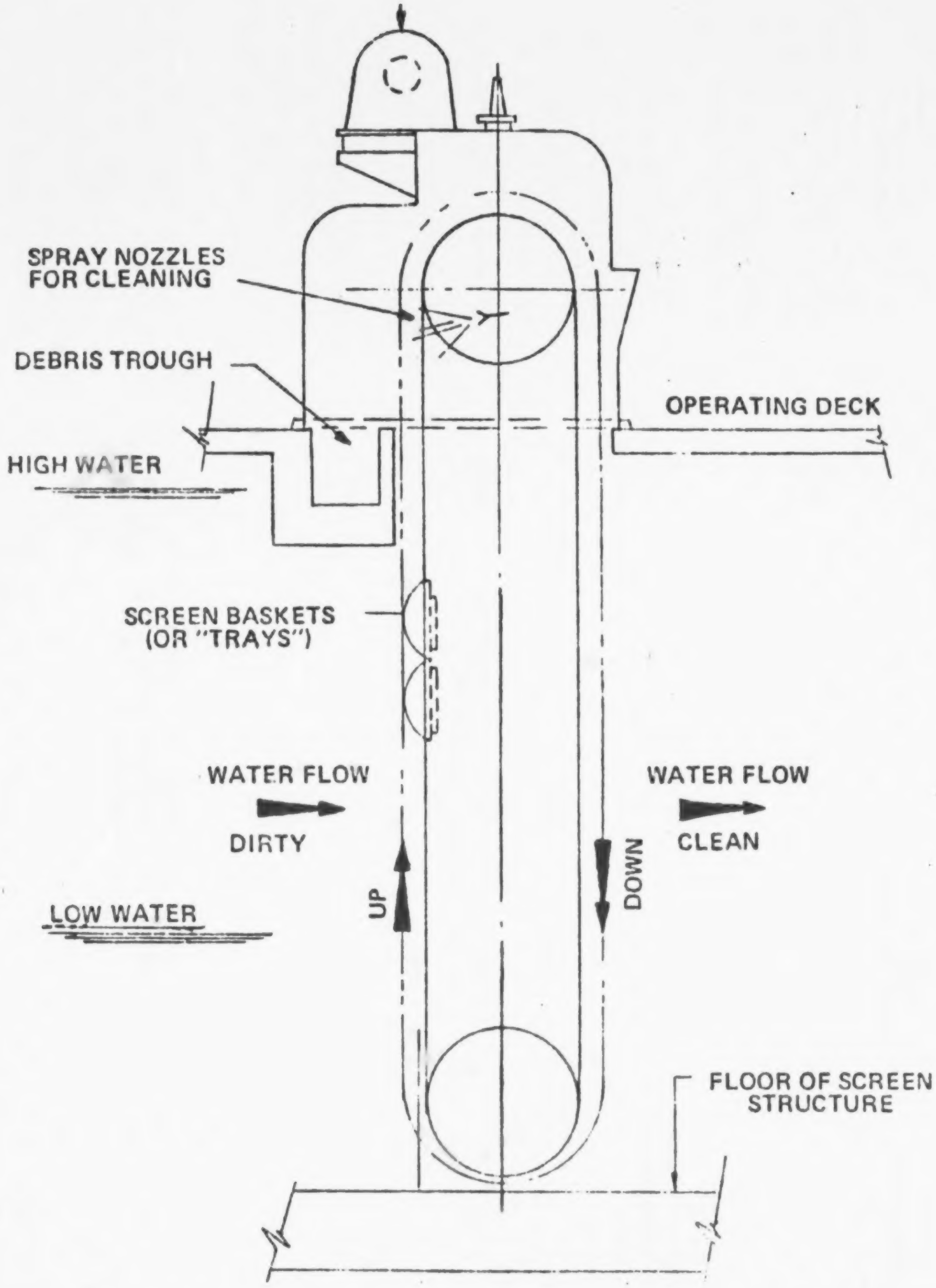
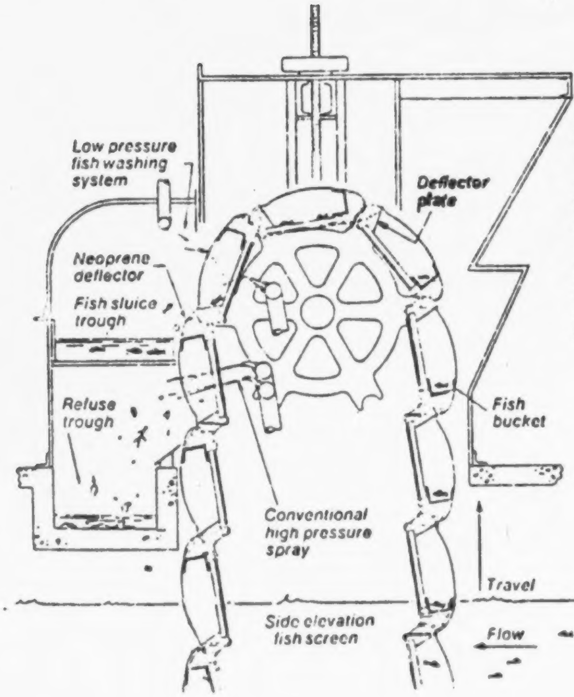
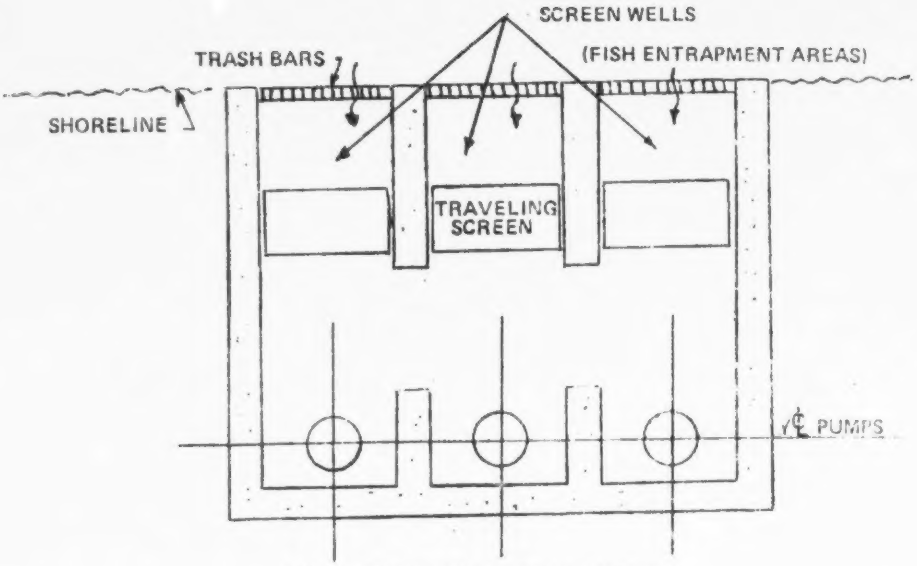

SPRAY NOZZLES FOR CLEANING
DEBRIS TROUGH
OPERATING DECK
HIGH WATER
SCREEN BASKETS (OR "TRAYS")
WATER FLOW
DIRTY
WATER FLOW
CLEAN
UP
DOWN
LOW WATER
FLOOR OF SCREEN STRUCTURE

Figure 11.1. Conventional vertical traveling screen(3).

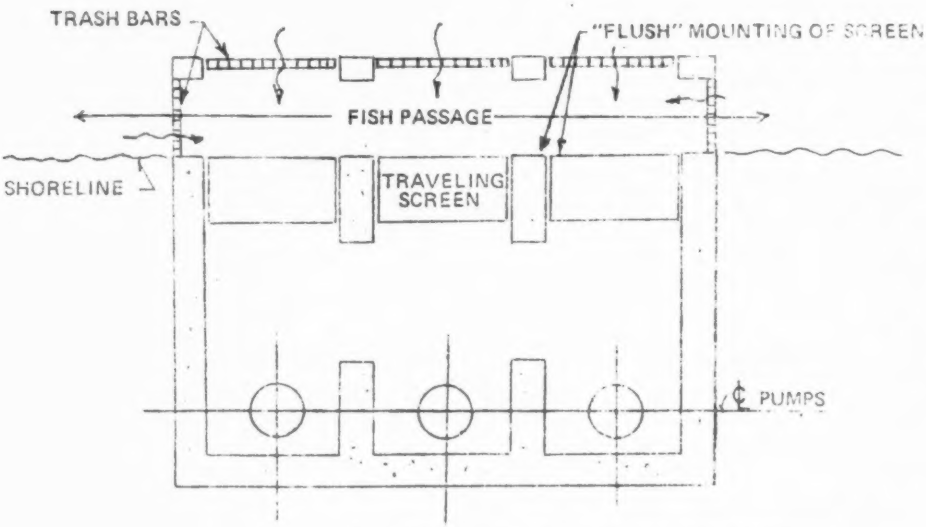

Low pressure fish washing system
Deflector plate
Neoprene deflector
Fish sluice trough
Refuse trough
Fish bucket
Conventional high pressure spray
Travel
Side elevation fish screen
Flow

Fish buckets exemplify steps taken to protect aquatic life in watercourses. Buckets replace trash lips that lift debris from water surface in conventional traveling screens. System shown is similar to one installed at Surry nuclear station

Figure 11.2. Modification of conventional traveling screens to protect impinged fish(3).

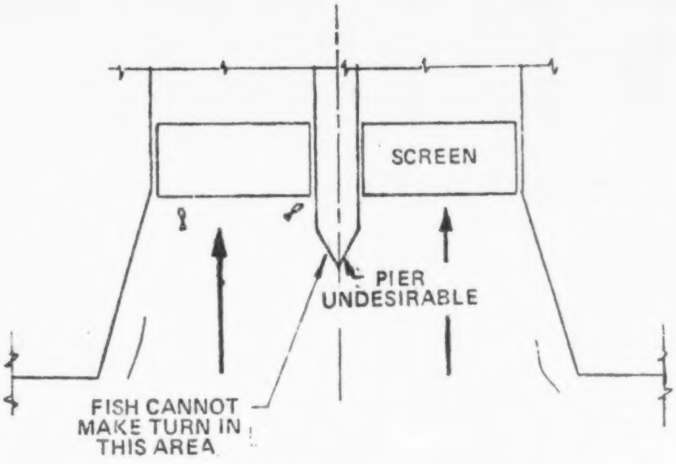

SCREEN WELLS
TRASH BARS
(FISH ENTRAPMENT AREAS)
SHORELINE
TRAVELING SCREEN
℄ PUMPS

(a) CONVENTIONAL SCREEN SETTING

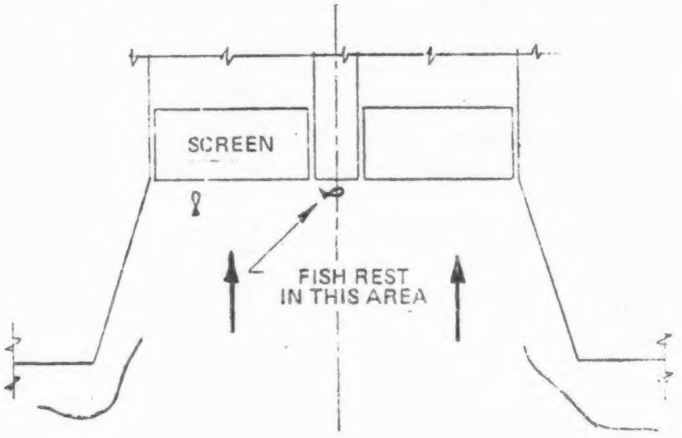

TRASH BARS
"FLUSH" MOUNTING OF SCREEN
FISH PASSAGE
SHORELINE
TRAVELING SCREEN
℄ PUMPS

(b) MODIFIED SCREEN SETTING (PREFERRED)

Figure 11.3. Screen settings(3).
(a) Conventional Screen setting
(b) Modified screen setting
(flush mounted)


SCREEN
PIER
UNDESIRABLE
FISH CANNOT
MAKE TURN IN
THIS AREA

(a) UNSATISFACTORY DESIGN


SCREEN
FISH REST
IN THIS AREA

(b) IMPROVED DESIGN

Figure 11.4. Pier design considerations(3).
(a) Pier design (unsatisfactory design)
(b) Pier design (improved design)

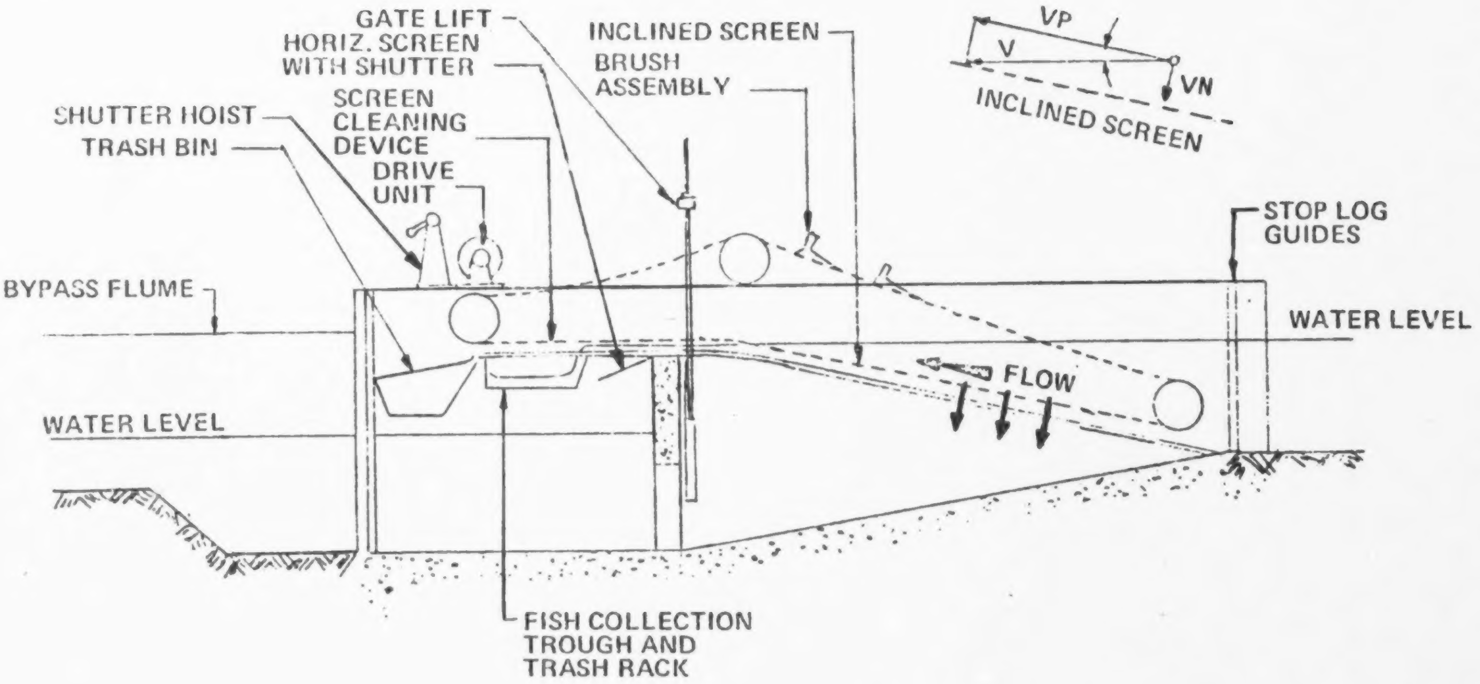

GATE LIFT
HORIZ. SCREEN WITH SHUTTER
SCREEN CLEANING DEVICE
DRIVE UNIT
SHUTTER HOIST
TRASH BIN
INCLINED SCREEN
BRUSH ASSEMBLY
VP
V
VN
INCLINED SCREEN
STOP LOG GUIDES
BYPASS FLUME
WATER LEVEL
FLOW
WATER LEVEL
FISH COLLECTION TROUGH AND TRASH RACK

Figure 11.5. Inclined plane screen with fish protection(3).

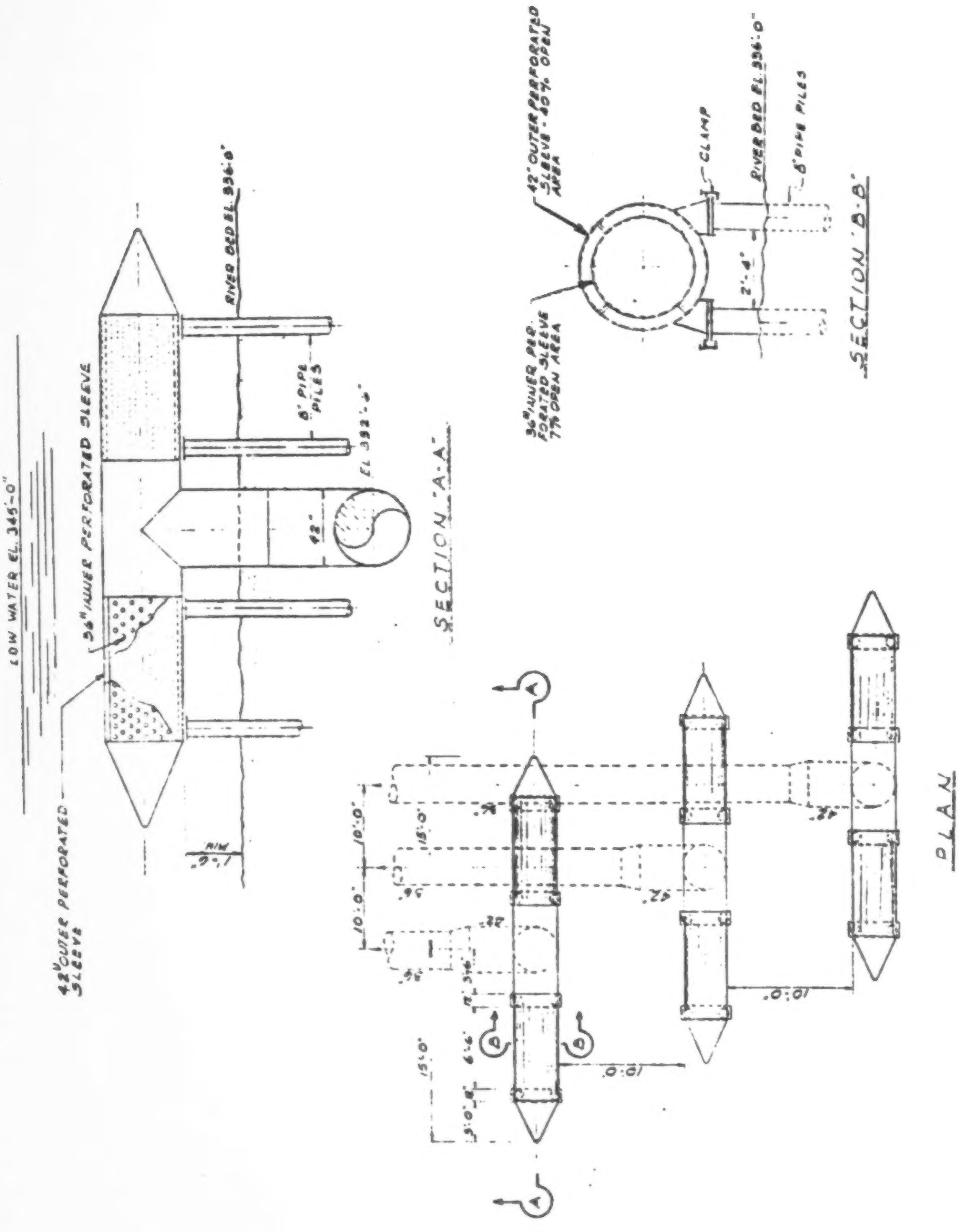
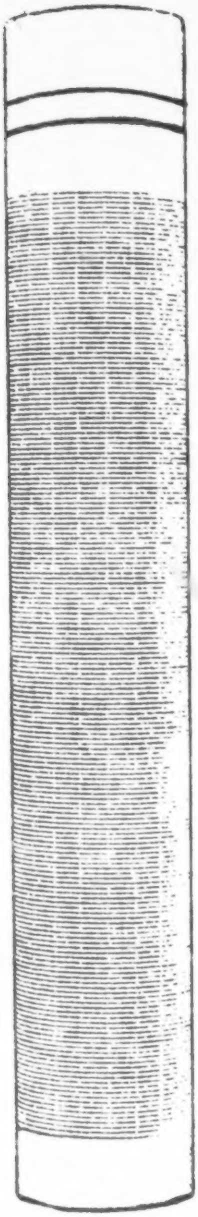
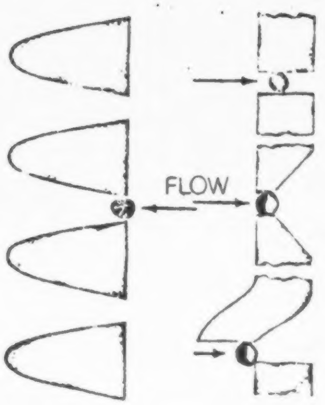

LOW WATER EL. 345'-0"
36" INNER PERFORATED SLEEVE
42" OUTER PERFORATED SLEEVE
RIVER BED EL. 336'-0"
8' PIPE PILES
EL 332'-0"
42"
1'-6" MIN
SECTION 'A-A'
42" OUTER PERFORATED SLEEVE - 40% OPEN AREA
36" INNER PERFORATED SLEEVE 7% OPEN AREA
CLAMP
RIVER BED EL. 336'-0"
8' PIPE PILES
2'-4"
SECTION 'B-B'
A
B
15'-0"
3'-0"
6'-6"
10'-0"
10'-0"
15'-0"
36"
42"
10'-0"
10'-0"
PLAN

Figure 11.6. Perforated pipe make-up water intake detail(11).

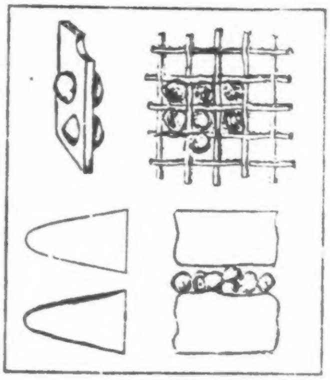
Reproduced from
best available copy.



JOHNSON Welded Well Screen



The full V-shaped, streamlined slot of JOHNSON Well Screens (left) passes extraneous materials freely without clogging. In contrast, non-continuous slots and square-cut forms of openings, shown at the right, are easily clogged and obstruct or divert the water during development of the well.



Wire meshes and round holes are easily plugged shut, but sand grains can only make the two-point contact on a continuous slot.

Figure 11.7. Johnson welded (wedge-wire) well screen(12).

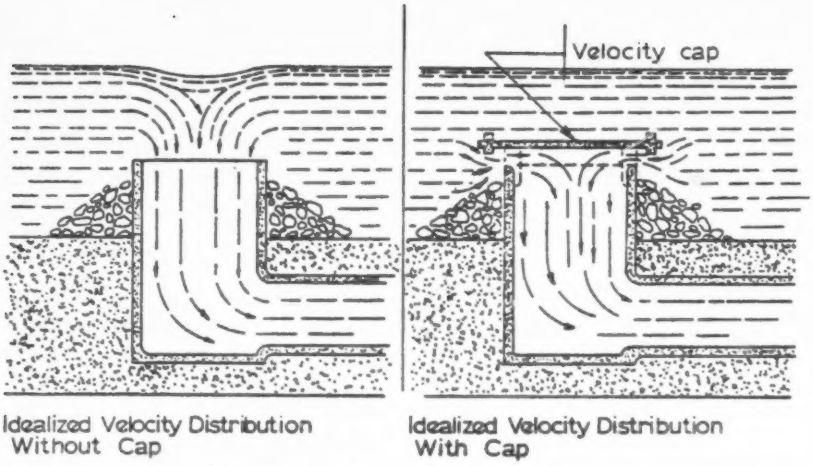

Velocity cap
Idealized Velocity Distribution Without Cap
Idealized Velocity Distribution With Cap

Figure 11.8. Operation of a velocity cap.

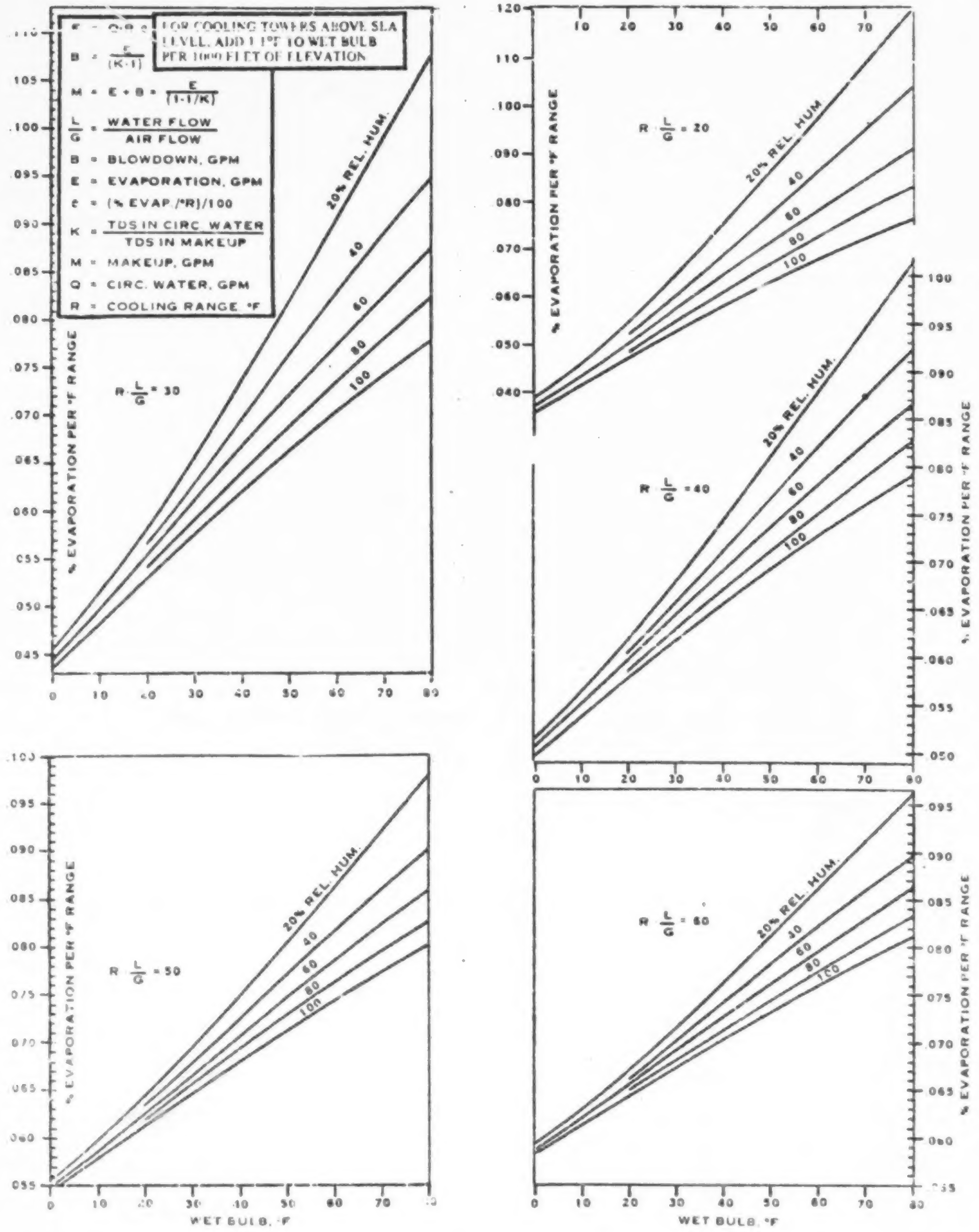


Figure 11.9. Cooling tower evaporation rate(20). Reprinted from Power Engineering, 1977, by T. H. Hamilton with permission of Technical Publishing Company.

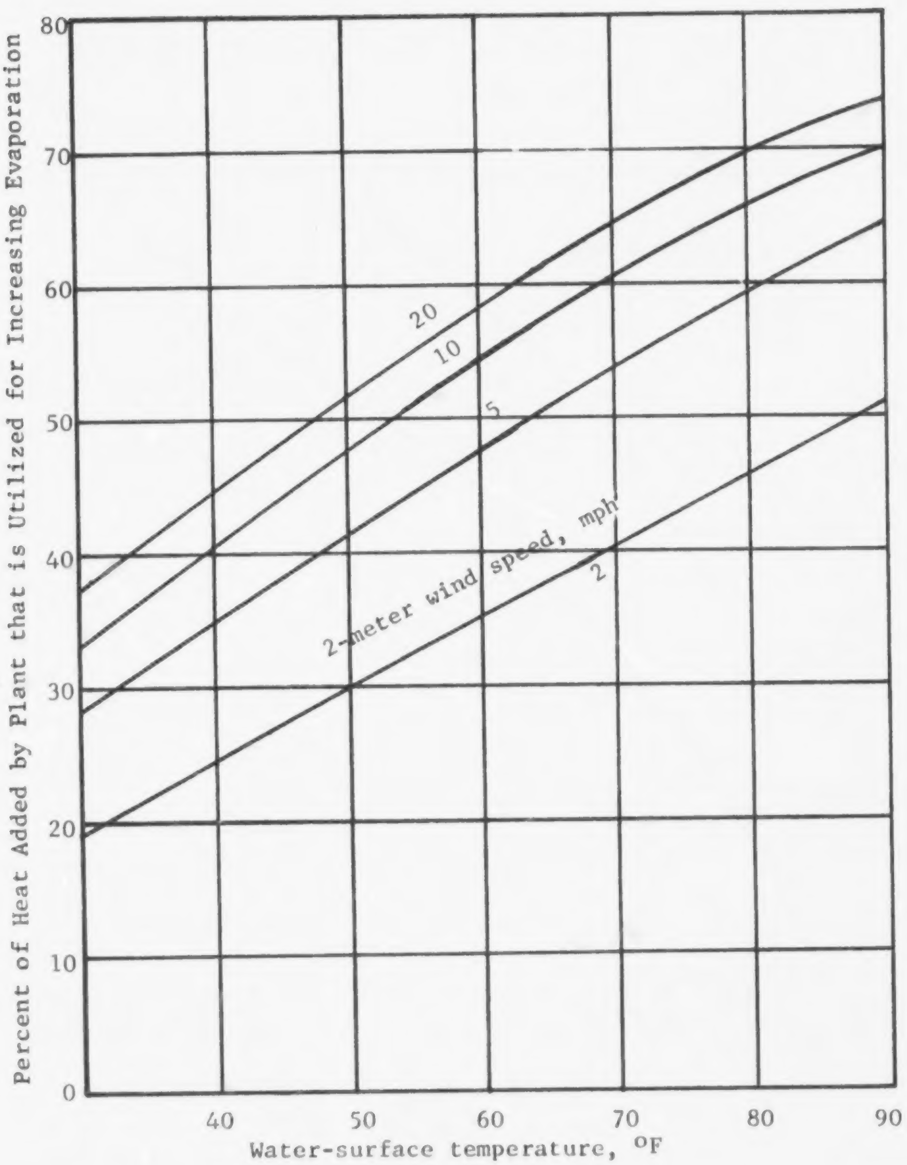


Figure 11.10. Estimating the increase in reservoir evaporation resulting from the addition of heat by a power plant(22).

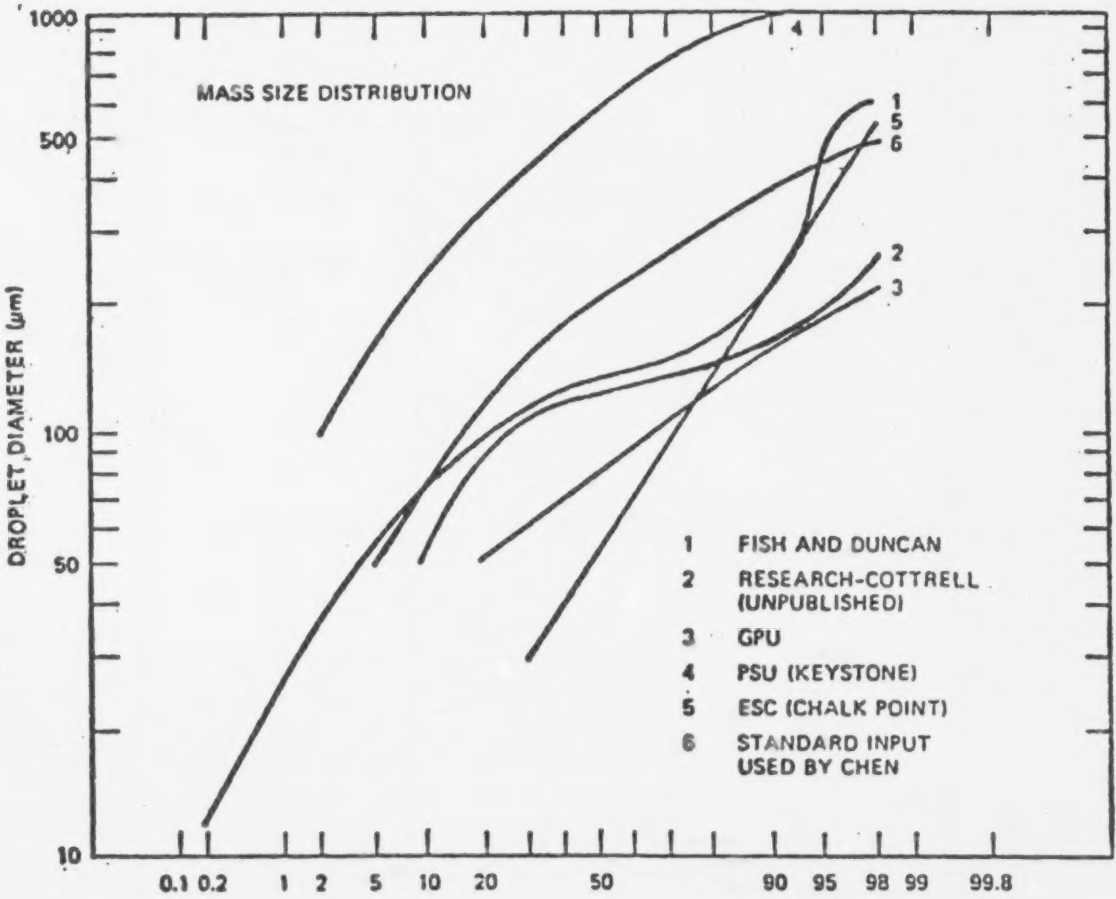


Figure 11.11. Cumulative mass distribution of drift droplets for natural draft cooling towers(45).

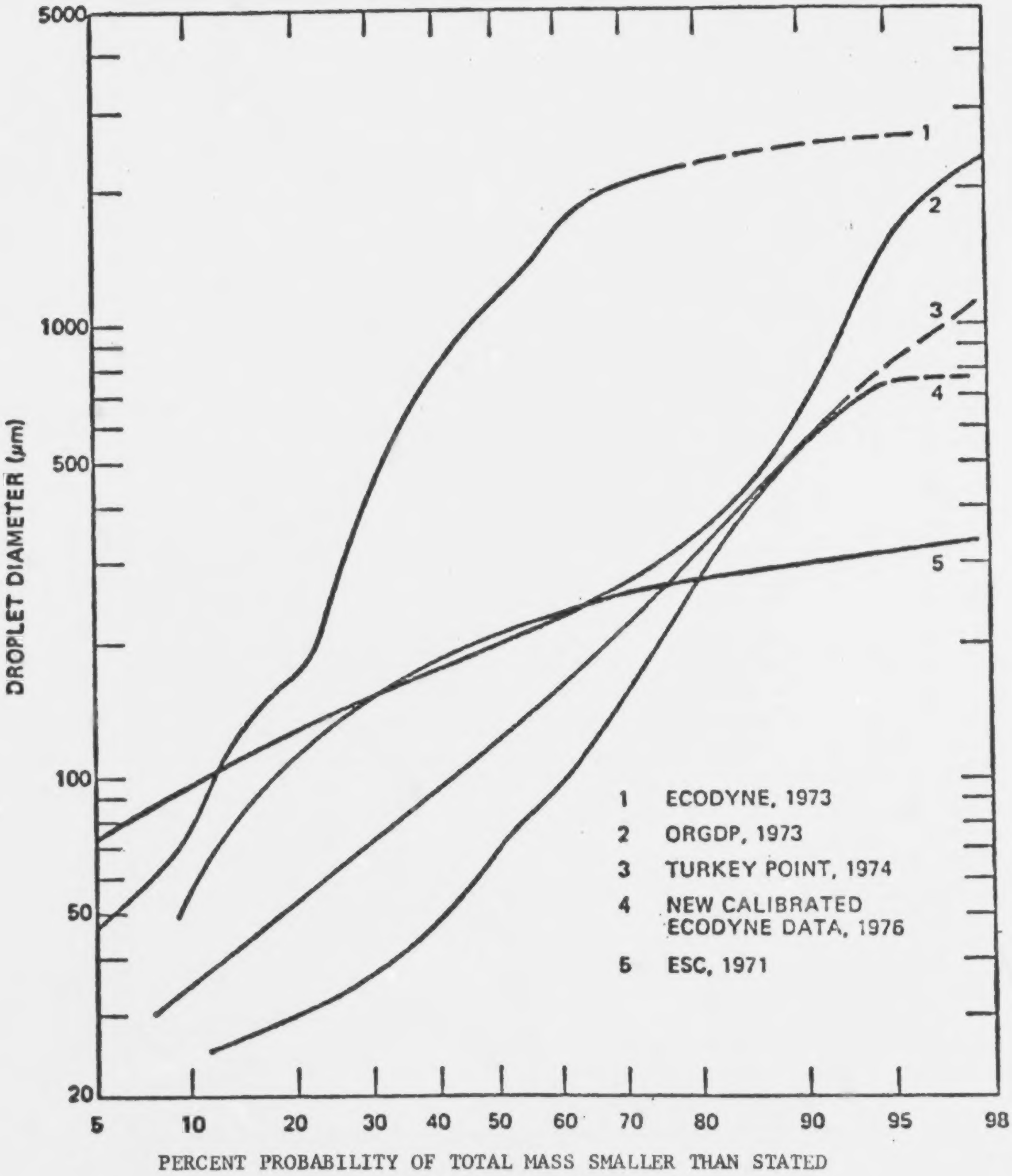


Figure 11.12. Cumulative mass distribution of drift droplets for mechanical draft cooling towers(45).

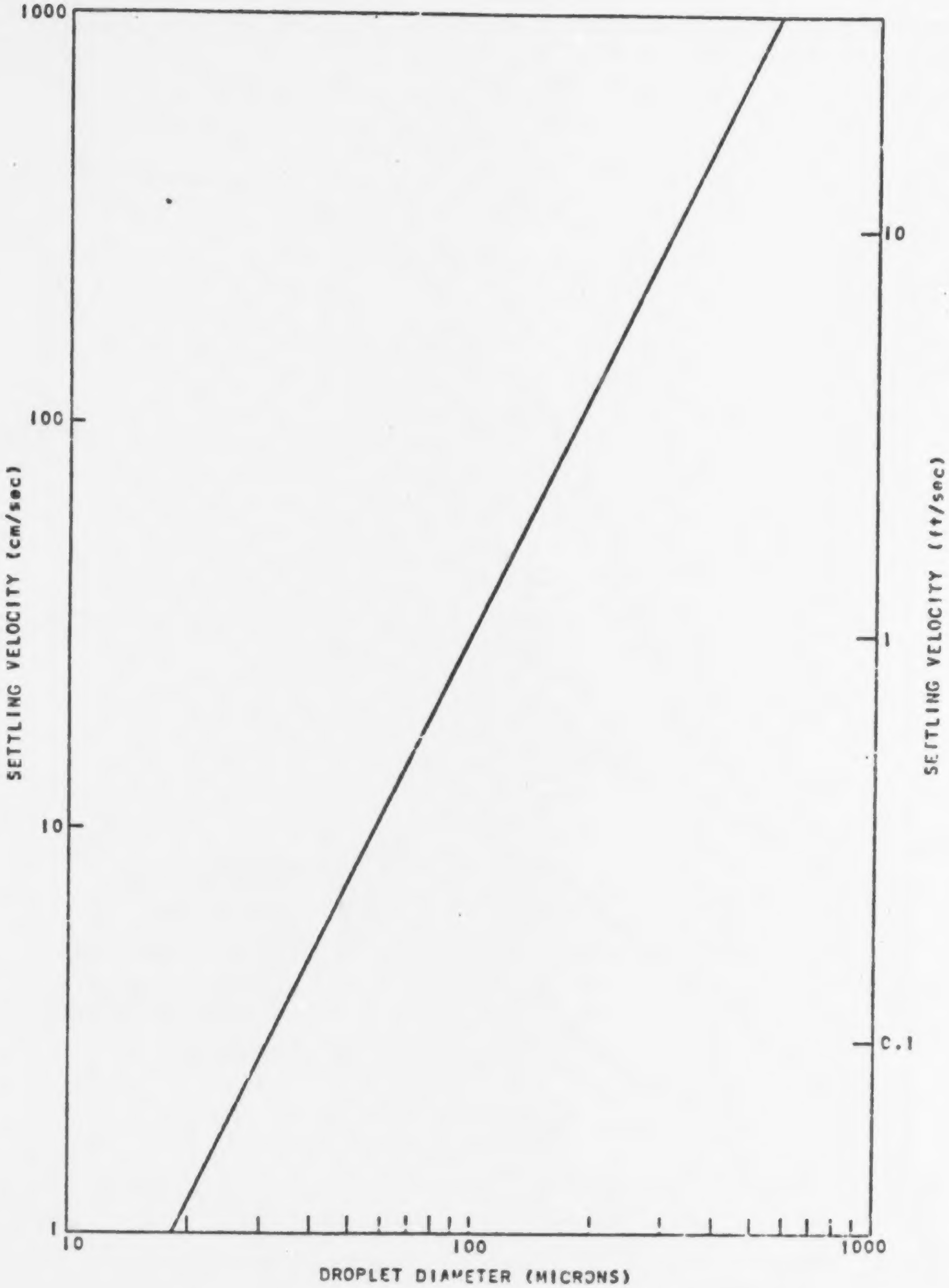


Figure 11.13. Nominal settling rate of water droplets in air(33).

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